June 14, 2021

The Honorable Chair and Members of the
Hawai‘i Public Utilities Commission
465 South King Street
Kekuanao‘a Building, First Floor
Honolulu, Hawai‘i 96813

Dear Commissioners:

Subject: Docket No. 2021-0024
Opening a Proceeding to Review Hawaiian Electric's Interconnection Process and Transition Plans for Retirement of Fossil Fuel Power Plants
Response to Commission's information requests

Hawaiian Electric[1] respectfully submits its responses to the Commission's information requests PUC-Hawaiian Electric-IR-16 through PUC-Hawaiian Electric-IR-19 issued on June 2, 2021.[2]

The response to PUC-Hawaiian Electric-IR-16 includes an electronic, non-confidential file, which is being provided via email to the Commission and the Consumer Advocate.[3]

Sincerely,

/s/ Kevin M. Katsura

Kevin M. Katsura
Director, Regulatory Non-Rate Proceedings

Enclosure

c: Division of Consumer Advocacy

[1] Hawaiian Electric Company, Inc., Maui Electric Company, Limited, and Hawai‘i Electric Light Company, Inc. are each doing business as "Hawaiian Electric" and have jointly registered "Hawaiian Electric" as a trade name with the State of Hawai‘i Department of Commerce and Consumer Affairs, as evidenced by Certificate of Registration No. 4235929, dated December 20, 2019.
[2] In accordance with Order No. 37043 *Setting Forth Public Utilities Commission Emergency Filing and Service Procedures related to COVID-19* (non-docketed), issued on March 13, 2020.
[3] Id.

PUC-Hawaiian Electric-IR-16

Reference: Hawaiian Electric's May 2021 Monthly Update, filed on May 21, 2021] and Hawaiian Electric Response to PUC-Hawaiian Electrlc-IR-13, filed on May 18, 2021.

Please update system reliability analyses for each month from 2022-2025, assuming the updated project schedules submitted in Hawaiian Electric's May 2021 Monthly Update, response to PUC-Hawaiian Electric-IR-13, regarding expected timelines to enroll customers in approved grid services contracts, and retirement of Waiau Units 3 and 4 in 2024.

The updated reliability analyses should include all relevant metrics to assess the reliability impacts of unit retirements and current project timelines for new resource additions.

Hawaiian Electric's Response:

Please refer to the attached Excel file PUC-IR-16 Attachment 1.xlsx for Hawaiian Electric's updated system reliability analyses for each month from 2022-2025, assuming the updated project schedules submitted in Hawaiian Electric's May Monthly Status Update report filed May 21, 2021 in this docket ("May 2021 Monthly Update"). The analysis herein provides an Energy Reserve Margins ("ERM") analysis that includes recently proposed schedule changes from the Kapolei Energy Storage project ("KES Project") as shown in the May 2021 Monthly Update. This analysis does not include the Barbers Point solar project, whose PPA has not yet been approved, and assumes the retirement of Waiau 3 and 4 in January 2024. For all other Stage 1 and 2 projects, their latest GCODs are modeled. The proposed accelerated GCODs for the Mililani I, Waiawa Solar Power, and Mahi Solar projects were not modeled, as Hawaiian Electric is still negotiating with the project developers, the terms of any accelerated GCOD, and any PPA amendment to reflect such accelerated GCOD would be subject to Commission approval.

The Company would like to make clear that under the proposed schedule changes to the KES Project, the Company expects sufficient reserve margins to meet customer demand for the remainder of 2022 and maintain ERM at 34% or higher (4% percentage points above the criteria). In addition, the Company expects sufficient reserve margins to meet customer demand through the end of 2025 with the Stage 1 and Stage 2 project additions and with the impact of the retirement of Waiau 3 and 4, which are rated for a total of 93 MW of firm capacity. This is consistent with previous presentations and materials presented to the Commission, as well as the Company's letter regarding *Updated Hawaiian Electric Energy Reserve Margins* filed in Docket No. 2020-0136, on June 4, 2021.

PUC-Hawaiian Electric-IR-17

Reference: Hawaiian Electric Response to PUC-Hawaiian Electrlc-IR-11, filed on May 18, 2021.

In response to PUC-Hawaiian Electric-IR-11, Hawaiian Electric stated, "[w]hile reactivation of Honolulu Unit 8 (H8) or Honolulu Unit 9 (H9) is technically possible, reactivation should only be considered as a last resort."

Given the limited new resources currently projected to come online by September 2022, the Commission is seeking additional information to review this option further;

a) Given the steps outlined in the response to PUC-Hawaiian Electric-IR-11, what is the latest point in time Hawaiian Electric can wait before making a final determination on whether to reactivate the plant?

b) Under what conditions would Hawaiian Electric decide to reactivate the plant?

Hawaiian Electric's Response:

a) With the Company's current maintenance schedules, even if there are no additional resources added by the time the AES coal facility is retired, the Company does not anticipate generation shortfalls, from a deterministic evaluation, before the end of 2022. A deterministic evaluation means that there is enough capacity minus loss of the largest unit on the system based on predicted peak loads. The Company has optimized the Waiau 5 overhaul schedule such that the required work will be completed and the unit will be available for service in early 2023 allowing for increased reserve margin around the IPP overhauls. However, if additional resources are not added by the August 2023 timeframe, the need to reactivate Honolulu 8 or Honolulu 9 may exist. The Company will be evaluating the progress of the Stage 1 and Stage 2 projects and will make an initial decision on the reactivation of either Honolulu Unit by the end of 2022.

b) As described in the Company's response to PUC-Hawaiian Electric-IR-12 in this docket and subart a. of this response, the Company does not foresee a likely scenario that would result in a generation shortfall, from a deterministic evaluation, earlier than August of 2023. Based on the Planned Maintenance Schedule and expected peaks, the Company believes that an addition of about 50 MW of capacity prior to August 2023 would be sufficient to offset the need to reactivate either of the Honolulu Units. If less than 50 MW of capacity is anticipated to be added by August 2023, reactivation of the Honolulu Units may be considered. The Kapolei Energy Storage project, or a combination of the other Stage 1 and Stage 2 projects, would meet this need. The Company believes that the possibility of needing to reactivate the Honolulu Units is very small, but will be monitoring the progress of the aforementioned projects and will evaluate the need to return either Honolulu Unit to service on an ongoing basis and, more specifically, at the end of 2022. A catastrophic loss of any other generating unit could result in the need to reactivate Honolulu Units to service. Such events would be unplanned and are one of the reasons that the Honolulu Units were deactivated as opposed to retired, as described in Hawaiian Electric's 2017 Test Year Rate Case, Docket 2016-0328.

PUC-Hawaiian Electric-IR-18

Reference: Hawaiian Electric Response to PUC-Hawaiian Electrlc-IR-15, filed on May 18, 2021.

Beginning in June 2022, the "Generation by Unit" tab in the supporting spreadsheets to PUC-Hawaiian Electric-IR-15 show a large increase in renewable energy from the "Waivers PV2" projects.

a) Which specific projects are included in the "Waivers PV2" designation?
b) Please further explain the increase in renewable output from these projects.
c) Why do the results indicate relatively lower levels of curtailment for the West Loch project when it has a later in-service date, which would provide it with a less senior position in the curtailment queue?

Hawaiian Electric's Response:

a) The projects included in the Waivers PV2 designation are:

Lanikuhana Solar, Waipio Solar, and Kawailoa Solar.

For clarification, the Waivers PV1 designation applies to Waianae Solar.

b) The increase in renewable energy output from Waivers PV2 projects and other projects is the result of the Kapolei Energy Storage project ("KES Project"), which was assumed to be added on to the system in June 2022 in the production simulation analysis. Adding the KES Project provides reserves that create additional "room" on the system by displacing thermal generating units, which need to run at a certain level of output in order to provide reserves.

c) In Hawaiian Electric's production simulation model analysis, West Loch PV was curtailed after the Waivers PV2 projects. The lower levels of absolute (MWh) curtailment shown for the West Loch PV project as compared to the Waivers PV2 block is reflective of the West Loch PV project being curtailed after energy from the Waiver PV2 projects are added on the system. A project's curtailment seniority date is set by the

Power Purchase Agreement ("PPA") and may vary slightly by the terms of the PPA. In general, a project's curtailment seniority date is set by its "Effective Date" (as defined under the PPA). Again, the definition of Effective Date can vary slightly from project to project, but is generally the Non-Appealable PUC Approval Order Date, as defined in the PPA.

The West Loch PV project is not an IPP project, but instead, is owned and operated by Hawaiian Electric. Given Hawaiian Electric's general policy to base curtailment seniority on the "effective date" of a PPA, for purposes of determining curtailment priority, the equivalent effective date for the West Loch PV project is June 30, 2017, which is the date the Commission issued Decision and Order No. 34676, which granted a waiver from competitive bidding for the West Loch PV project and approved Hawaiian Electric's commitment of funds for the West Loch PV project and recovery of costs subject to certain conditions.

The Lanikuhana Solar, Waipio PV and Kawailoa Solar PPAs were the subject of a consolidated proceeding opened by the Commission (Docket 2017-0108). On July 27, 2017, the Commission issued Decision and Order No. 34714, approving, subject to certain conditions, the three amended power purchase agreements. On August 7, 2017, the Consumer Advocate filed a motion seeking to modify Decision and Order No. 34714 by adding two conditions. The Commission, on its own motion, modified D&O 34714 on August 16, 2017. The Non-appealable PUC Approval Order date for these PPAs is September 16, 2017. The Lanikuhana Solar and Waipio PV projects are part of Curtailment Block B, and would be curtailed before the West Loch PV project and Curtailment Block A (Waianae Solar). Kawailoa Solar did not reach the Qualifying

Deadline of October 8, 2019 under its PPA, excluding Kawailoa Solar from eligibility in Block B. Therefore, Kawailoa Solar is curtailed even before Lanikuhana Solar and Waipio PV (Curtailment Block B), West Loch PV, and Curtailment Block A (Waianae Solar).

PUC-Hawaiian Electric-IR-19

Reference: Letter from Hawaiian Electric to Commission re: Opening a Proceeding to Review Hawaiian Electric's Interconnection Process and Transition Plans for Retirement of Fossil Fuel Power Plants; "Response to Commission request in April 13, 2021 Status Conference," filed on May 28, 2021 ("May 28 Letter").

In its May 28 Letter, Hawaiian Electric submitted initial findings from its Stage 2 System Impact Studies.

Please file the studies/analyses summarized in the May 28 Letter.

<u>Hawaiian Electric's Response</u>:

Please see Attachment 1 for the island-wide PSCAD study conducted as part of the Stage 2 System Impact Study to evaluate each project's proposed equipment to meet the grid forming inverter PPA requirements and its impact on each island system's stability. Due to the technical complexity and industry-leading work contained in this study, the Company plans to present and discuss the details of the study in a future IGP meeting.

Hawaiian Electric Island-Wide PSCAD Studies
(Stage 2 System Impact Study)

June 11, 2021

Report Submitted to:
Hawaiian Electric Company

Lukas Unruh
Anuradha Kariyawasam
Suren Dadallage
Andrew Isaacs

ELECTRANIX
SPECIALISTS IN POWER SYSTEM STUDIES

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Appendices

1 Executive Summary

1.1 Background

Nine new utility-scale PV plus storage projects and three new standalone storage projects are being proposed for integration into the Oahu, Maui and Hawaii Island power systems as part of the Hawaiian Electric's RFP Stage 2.[1] These projects are part of the second stage of projects which were submitted through a competitive bidding process undertaken to help the state of Hawaii achieve 100% renewable generation by the year 2045. High penetration of Distributed Energy Resources (DER) and plans to reduce operation of significant amounts of conventional thermal generation resources in the near term are likely to introduce scenarios with nearly 100% renewable generation by 2023. Power systems which rely nearly exclusively upon Inverter Based Resources (IBRs) such as wind, PV solar, and batteries are new to the industry, and significant concerns about system stability and reliability exist for these systems.

In order to prepare for this future, Hawaiian Electric Company requested special control functionality (termed "Grid Forming" or GFM[2]) from each Stage 2 project which included battery resources, and commissioned a unique study which modelled each of the three islands in an unprecedented level of detail using the PSCAD/EMTDC simulation tool.

The objectives of this study were threefold:

1. To evaluate the potential for reliability concerns in the 2023 timeframe if GFM control technology from Stage 2 projects was not employed.
2. To evaluate the ability of Stage 2 project's GFM controls to improve system performance, and identify potential risks in implementation of this new technology.
3. To recommend specific changes to Stage 2 projects to help mitigate reliability risks, and identify avenues for future work which will be required to make the Hawaiian Electric island power systems robust as conventional thermal generation is retired or operations reduced.

It is notable that the scenarios evaluated in this study are beyond what is considered normal grid operations and are not well understood in the industry. These studies are accordingly unusually complex, with many important, and in some cases untested, modelling assumptions built in. In addition, the GFM equipment being proposed is conceptually new and untested. All of these factors and others will lead to a degree of unavoidable uncertainty in predicting the impact on future power system reliability.

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[1] Maui (Pulehu Solar, Kahana Solar, Waena BESS, Kamaole Solar), Oahu (Kapolei Energy Storage, Kupehau Solar, Mahi Solar, Barbers Pt Solar, Waiawa Phase 2 Solar, Mountain View Solar), Hawaii Island (Puako Solar, Keahole BESS). Note, however, that Kamaole Solar was not included in the analysis of this report due to the timing of project changes.

[2] The primary objective of grid-forming controls for transmission connected inverter-based renewable (IBR) generation is to maintain an internal voltage phasor that is constant in the sub-transient to transient time frame, without relying on synchronization with the external grid during this period. This allows the IBR to immediately respond to changes in the external system, and provides stability in the controls during challenging network conditions. The voltage phasor must be controlled to maintain synchronism with other devices in the grid, and must also regulate active and reactive power appropriately to support the grid. This is in contrast to grid-following control technology, which relies on fast measurement of the external system quantities to maintain constant currents during this period, but may struggle under weak or high penetration scenarios. Most IBRs installed globally use grid-following technology.

1.2 Results and Recommendations

The following key results and recommendations are common to all three islands (O‘ahu, Maui, and Hawai‘i Island).

1.2.1 GFM Technology

Conventional Grid-Following (GFL)[2] control technology is currently the industry standard for PV solar, wind, and battery resources, such as those employed as part of the Stage 1 projects. The use of GFL technology in Stage 2 projects is inadequate for maintaining reliable system operation under the severe dispatches considered in this analysis. Implementing commercially available GFM technology, as required in the project Power Purchase Agreements in Stage 2, battery projects provides significant steady state performance improvements and improves recovery from studied system events. It is notable that GFM technology is new and the extent of its application envisioned in this study is beyond that seen in industrial applications to date.

Recommendation: Notwithstanding that technical issues may remain with GFM technology, Hawaiian Electric should proceed to implement GFM controls in Stage 2 projects prior to operating the system in scenarios envisioned for 2023. Synchronous condensers could be explored as a supplemental technology to assist GFM in stabilizing future scenarios.

Recommendation: Hawaiian Electric should continue to require and implement grid-forming control technology in all new battery energy storage system (BESS) devices for future projects. Future Requests for Proposals (RFPs) for GFM technology should improve clarity on technical requirements based on outcomes from this study.

Recommendation: It is noted that GFM technology may become available in non-BESS devices such as PV or wind. However, GFM in non-BESS devices is not currently commercially available, and is expected to come with a cost premium and reduced stability benefit. Hawaiian Electric should continue to monitor industry developments in this area.

1.2.2 DER Blocking

In all the scenarios studied, DER represents a very significant portion of the generation mix. DER is generally not subject to the same criteria for providing grid support functions, and is prone to blocking or ceasing injection of active and reactive power during faults or system events. Following fault clearing, most or all of the DER may cease to inject power, causing significant rapid frequency decay in the islands, along with suppressed voltages which may prevent the DER from un-blocking. This can lead to loss of load due to under-frequency load shed (UFLS) or system instability.

Recommendation: The specific settings in the DER models are critical in determining whether DER will recover correctly from fault events or contribute to under-frequency and under-voltage issues. These models should be further validated, including checking against existing surveys or research into existing DER installations, and updated if required. In addition, the impact of using single-phase DER resources on blocking should be reviewed and if necessary, the three phase models used in this study should be updated in future work to improve blocking representation for unbalanced faults.

Recommendation: Existing DER resources should be adjusted to lower block/unblock thresholds, and all future DER resources should be required to provide improved ride-through capability. In particular, DER should not block above a specified per unit voltage, should not delay in returning to normal current injection following voltage recovery, and should not be limited by a ramp rate.

1.2.3 Frequency Response

As conventional generation is retired and penetration of DER based generation rises, frequency becomes more challenging to manage in the Hawaiian Electric island systems. The system frequency deviation following significant fault-induced loss of DER generation is observed to trigger UFLS in select cases.

Recommendation: In order to limit the frequency deviation and reduce the chance of load-shedding or instability following DER blocking or other loss of IBR resources, frequency response from existing and new resources (Stage 1 and 2 projects) should be increased as much as possible while maintaining island-wide coordination. This may include reducing active power/frequency droop settings in the Stage 1 and 2 plants, or may include procurement of dedicated frequency response contingency resources(s) for rapidly responding to frequency events and mitigating or preventing the loss of DER.

1.2.4 Voltage Control

The post-fault system voltage was observed to recover slowly or not recover at all without the help of UFLS on all three islands. DER active power blocking due to undervoltage was identified as the root cause of this issue. In this analysis, it was shown that tuning the Stage 1 and 2 voltage controllers to supply more reactive power to the system in the post-fault state is effective in increasing the system voltage to a point at which the DER active power can unblock and prevent UFLS.

Recommendation: Stage 1 and 2 voltage control response should be improved through control tuning to supply reactive power during faults, and supply more reactive power during nominal undervoltages. Supplemental voltage control devices, such as STATCOMS or synchronous condensers, could be explored to assist with voltage control. DER voltage control may be also be enabled as part of the solution, though this would require extensive testing.

Recommendation: Future PPAs should consider specifying additional performance requirements for voltage control, including response characteristics, Q priority, and VAR capability at zero or low active power levels.

1.2.5 Battery Operation and Reserve

The significant performance improvements gained by implementing GFM controls requires that the batteries have sufficient current headroom to respond to system events. Many of the severe cases studied include GFM standalone battery projects dispatched at full charging, which allows them to immediately respond powerfully to DER blocking or other loss of generation. If batteries are dispatched at max current levels, the stabilizing influence from GFM controls may be reduced, and if they are dispatched at full discharge when an underfrequency event occurs, their impact on frequency is greatly diminished.

Recommendation: Sufficient current and energy headroom in battery resources should be reserved to accommodate realistic loss of generation scenarios. Some reserve margin may be required in GFM battery resources to allow grid stabilizing benefit from the controls.

Recommendation: The primary use case envisioned for these resources is energy arbitrage which may conflict with the identified need to potentially carry frequency responsive reserves on these resources and could impact the economics used to evaluate selection of these resources. Additional economic analysis which varies the use cases to ensure system security and adequacy of energy supply could be warranted in future work.

Recommendation: Since battery resources have a greater capacity to respond to under-frequency events when dispatched in a charging mode, it may be beneficial for operators to allow batteries to charge from the grid in some circumstances.

1.2.6 Damping Concerns

Although significant benefit is obtained by implementing GFM technology in battery resources for very high renewable penetration scenarios, many of these scenarios also show oscillations in power and voltage quantities across the system. Undamped oscillations such as these may result in equipment damage or uncontrolled tripping of transmission elements. The source of these oscillations has not been completely identified at the present time, but they are present under outage conditions when GFM controls are active.

Recommendation: The source of undamped oscillations in GFM cases should be identified through additional study and mitigated, either through external equipment or through control tuning in the battery projects.

1.2.7 Delayed Fault Clearing

Many of the worst events seen in this analysis result from delayed clearing due to absent pilot schemes on transmission line protection. Extended faults on the system cause the DER to remain blocked for a longer period and the frequency to decay further.

Recommendation: Where possible, dual-pilot protection (i.e., redundant protection components and dual diverse communication) to enable fast remote-end clearing of lines should be implemented.

1.2.8 Digital Fault Recorder Installation

Regardless of model accuracy, actual scenarios and equipment configurations will differ from those studied. Since much of the GFM equipment is new, and only limited understanding of the DER controls is available, validation of the models will be useful as Hawaiian Electric gains operational experience with high penetration scenarios. As faults and events happen in the system, high resolution recordings of these events are very valuable for model validation and operational understanding.

Recommendation: High resolution Digital Fault Recorders (DFRs) should be installed at key locations throughout the islands, and the data should be made available to planning, protection, and operations engineers.

1.2.9 Plant Specific Recommendations

Recommendation: Control parameters for many plants in the Stage 1 and 2 groups were adjusted to improve system performance. These parameters should be reviewed with the generator owners and the affected OEMs. Further control tuning and sensitivity studies may be required as equipment and understanding evolves further. All changes made to the control models are documented in Appendix A. Any deviations in the final as built equipment from the specific models as configured in this study may introduce risks to system reliability and should be reviewed.

Recommendation: Control recommendations specific to each project have been documented in Appendix A and should be implemented if possible following review by those OEMs as default parameters unless overridden by site-specific recommendations. Final settings of equipment being commissioned should be checked against the settings used and recommended in pertinent studies.

1.2.10 UFLS Effectiveness

It is noted that much of the DER resource is connected behind breakers operated by UFLS relays. This diminishes the effectiveness of UFLS as a system level protection against collapse.

Recommendation: Although UFLS remains effective in restoring system balance following loss of generation, the configuration of the UFLS system should be reviewed and configured and optimized to disconnect load without disconnecting generation if possible.

Recommendation: To a limited extent, UFLS action may be supplanted by additional under-frequency response behaviour from distribution connected resources, such as DER aggregators which include battery resources and load which is configured to automatically disconnect during underfrequency as a service. However, for these resources to be effective, robust fault ride-through capability will be required, and the resource response characteristics must be carefully coordinated with the demands of critical outages and existing UFLS scheme and the UFLS block setpoints.

1.2.11 Additional Studies

Following review by Hawaiian Electric planning and operations groups, further scenarios and sensitivities should be evaluated based on known potential configurations. Prior to those sensitivities being run, control recommendations and study outcomes from this effort should be reviewed with the respective generator owners and OEMs. Sensitivities considered should include:

1. Synchronous condenser placement – can they be used to supplement GFM batteries?
2. Sensitivity to battery dispatch. In particular, stand-alone batteries which were dispatched in a charging mode were particularly effective at preventing UFLS in the study, and additional dispatches where these devices have less available discharge headroom should be considered.
3. If significant changes are made to control hardware or software prior to commissioning, key contingencies should be tested with final configurations and control topologies.

In addition to these sensitivities the following should also be considered:

4. Impact on protection following retirement of key synchronous units. The PSCAD system models developed for this study effort can be used to assist protection engineers in validating their protection models.
5. Several contingencies showed significant stability issues related to GFM control tuning for relatively large projects. These are documented in Appendix A. Further discussion with the respective OEMs should be had and controls should be tuned and updated.
6. Several scenarios showed poor control response from individual projects. These projects were not large enough to severely impact the island dynamics, and only minimal effort was done to improve these controls. Further tuning could improve system performance, but may require significant time and effort.

1.3 Acknowledgements

The assistance of the following individuals and groups provided valuable support and assistance in this effort: Hawaiian Electric, Hawaiʻi Electric Light, Maui Electric – Interconnection Services, Transmission Planning, System Operations, and other supporting divisions, consulting engineers from Siemens , Quanta, and Leidos , Andy Hoke and Wallace Kenyon (NREL/DOE) and their parallel PSCAD modelling research effort on the island of Maui.

2 Assumptions and Methodology

2.1 PSCAD and E-Tran Software

Inverter-based resource (IBR) control interactions and instabilities are often not detectable using positive sequence simulation tools such as PSS/E software since these models usually do not represent the fast inner controllers that are responsible for the unstable modes, or protection circuits which can cause ride-through failure. More complex studies using Electromagnetic transient (EMT) tools such as PSCAD software are required to identify control interactions or control instability for power electronic resources connected to weak grids.

The studies in this report were completed using the PSCAD/EMTDC program (V4.6.3). The E-Tran program (5.2.0.6) was used to translate PSS/E .raw power flow cases into PSCAD models.

Detailed models such as transmission lines, fault logic, Wind turbines, and Solar plants are maintained in PSCAD "substitution libraries" and are automatically imported into the PSCAD case (and initialized) by E-Tran.

2.2 PSCAD Parallel System Model

2.2.4 PSCAD Parallel Processing Capabilities

The modeling approach used in these studies employs parallel processing using a commercially available PSCAD add-on program called "E-Tran Plus for PSCAD" as shown in Figure 2.1 (see reference paper entitled "Parallel Processing and Hybrid Simulation for HVDC/VSC PSCAD Studies", ACDC conference 2012).

Simulation speed issues are solved by placing each IBR onto its own CPU/CORE (either on one computer or on other computers connected to the LAN). Each wind farm is modeled on its own CPU/processor (through a Bergeron line model or scaling transformer model) – this allows each wind farm PSCAD model to:

- use a different time step (so the entire simulation is not slowed down if one model needs a smaller time step)
- to be compiled with different Fortran/C compilers (solving compiling/linking/compatibility issues)
- to be generated with different versions of PSCAD (i.e. older PSCAD V4.2.1 models can be run with PSCAD V4.6.3/newer versions)
- be completely black-boxed to solve confidentiality problems. The total linked executable .exe needs to be pre-generated by PSCAD, but once available, individual *.f source code for each page/model, PSCAD models/components/data do not need to be distributed.
- The modeling approach used in these studies is based on a database approach – i.e. each detailed model is maintained in a PSCAD/E-Tran database, which allows a PSCAD case to be quickly generated for any existing or future loadflow conditions. The simulations are also more accurate, because the complete system and wind farm models are fully initialized by the standard PSS/E loadflow setup.

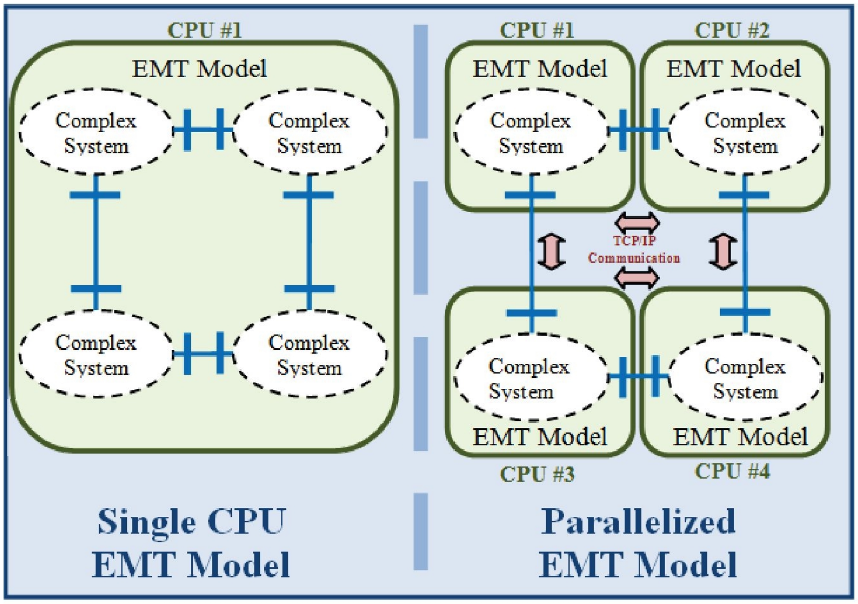

Figure 2.1: PSCAD single processing Vs. E-Tran Plus Parallel Processing in PSCAD.

The "E-Tran Plus for PSCAD" parallel processing method also includes the following features:

- Auto-start component - a single "start" button on one PSCAD case will automatically launch all other cases, including duplication of settings (i.e. if the main PSCAD case is setup to write output files, then all cases will run output files) – if the main case takes a snapshot at 1 second, they all take snapshots at 1 second etc.). This includes starting the PSCAD processes on remote computers, killing processes (which during initial debugging may not have exited cleanly), starting with the process priority and locked to a given cpu core (although the "auto" assignment of processes to cores is recommended), etc.
- Communication/plotting between PSCAD cases (an array of any size can be assigned to transfer variables from one case to another – this is useful if real/physical communication is required (say a line relay at one side communicates with the other via fiber) or simply for plotting (so the main simulation can plot quantities from the entire set of simulations).
- Compatibility with the multiple run features of PSCAD.

The communication method used between processes is based on standard TCP/IP networking protocols, using custom code (included in E-Tran Plus products) written with low-level (i.e. no overhead) interfaces and absolute minimum latency requirements (i.e. a standard LAN gigabit switch is sufficient).

2.2.5 Application of PSCAD Parallel Processing

Each of the existing, Stage 1, and Stage 2 renewable plants were modelled in individual parallel PSCAD cases. The generic solar inverters used to represent the DER were also modelled in individual PSCAD cases. Maui and Hawaii Island had a single system case which contained all the transmission lines, transformers, loads, shunt elements, and synchronous machines. The Oahu system case was split into three parts in order to increase simulation speed. The system cases contain an E-Tran Plus Autolaunch component which launches all other parallel cases upon start.

2.3 Island-Wide PSCAD System Models

Detailed models of each transmission connected plant were provided by plant developers in accordance with the requirements in the RFP, or developed in conjunction with Hawaiian Electric. These models were tested individually and held to a very high quality standard for accuracy and usability. It is noted that where manufacturer specific models were unavailable, detailed generic models were used.

2.3.1 Oahu Utility-Scale Inverter Based Resources

Table 2.7: Oahu List of Utility-Scale IBRs in PSCAD Model

Project Name	Generation Group*	Technology	Generation Size	BESS Size
Kupehau	Stage 2	PV+BESS	60 MW	240 MWh
Waiawa Phase 2 - # 1	Stage 2	PV+BESS	15 MW	120 MWh
Waiawa Phase 2 - # 2	Stage 2	PV+BESS	15 MW	120 MWh
Mountain View Dairy	Stage 2	PV+BESS	7 MW	35 MWh
Barbers Point Solar	Stage 2	PV+BESS	15 MW	60MWh
Mahi Solar	Stage 2	PV+BESS	120 MW	480MWh
Kapolei Energy Storage	Stage 2	BESS+Contingency BESS	n/a	135MW / 540MWh + 50 MW / 25MWh FFR
West Oahu Solar	Stage 1	PV+BESS	12.5 MW	50 MWh
Ho'ohana Phase 1	Stage 1	PV+BESS	52 MW	218 MWh
Mililani Phase 1	Stage 1	PV+BESS	39 MW	156 MWh
Waiawa Phase 1	Stage 1	PV+BESS	36 MW	144 MWh
Kahuku Wind	Existing	Wind	30 MW	N/A
Kawailoa Wind Makai	Existing	Wind	18.4 MW	N/A
Kawailoa Wind Mauka	Existing	Wind	50 MW	N/A
Kawailoa Solar Makai	Existing	Solar	21 MW	N/A
Kawailoa Solar Mauka	Existing	Solar	30 MW	N/A
Lanikuhana Solar	Existing	Solar	14.7 MW	N/A
Waipio Solar	Existing	Solar	45.9 MW	N/A
Na Pua Makani Wind	Existing	Wind	24 MW	N/A
Waianae Solar	Existing	Solar	27.6 MW	N/A
West Loch PV	Existing	Solar	20 MW	N/A
KREP PV	Existing	Solar	5 MW	N/A
KS2 PV	Existing	Solar	5 MW	N/A

2.3.2 Maui Utility-Scale Inverter Based Resources

Table 2.8: Maui List of Utility-Scale IBRs in PSCAD Model

Project Name	Generation Group	Technology	Generation Size	BESS Size
Kahana Solar	Stage 2	PV+BESS	20 MW	80 MWh
Pulehu Solar	Stage 2	PV+BESS	40 MW	160MWh
Waena BESS	Stage 2	BESS	n/a	40 MW / 160 MWh
Kuihelani Solar	Stage 1	PV+BESS	60 MW	240 MWh
Paeahu	Stage 1	PV+BESS	15 MW	60 MWh
KWP I	Existing	Wind	30 MW	n/a
KWP II	Existing	Wind+BESS	21 MW	9 MVA
Auwahi	Existing	Wind+BESS	24 MW	11 MVA
Kuia Solar	Existing	Solar	2.9 MW	n/a
SMRR	Existing	Solar	2.9 MW	n/a

2.3.3 Hawaii Island Utility-Scale Inverter Based Resources

Table 2.9: Hawaii Island List of Utility-Scale IBRs in PSCAD Model

Project Name	Generation Group	Technology	Generation Size	BESS Size
Puako Solar PV + Battery Storage	Stage 2	PV+BESS	60 MW	240 MWh
Keahole Battery Energy Storage	Stage 2	Contingency BESS	n/a	12 MW / 12 MWh
Waikoloa Solar	Stage 1	PV+BESS	30 MW	120 MWh
Hale Kuawehi	Stage 1	PV+BESS	30 MW	120 MWh
Apollo	Existing	Wind	20.5 MW	n/a
HRD	Existing	Wind	10.5 MW	n/a

2.3.4 Synchronous Machines

Any dispatched thermal generation was modelled using the PSS/E transient stability models as source data for detailed PSCAD models. The dynamic models were automatically translated into the PSCAD case by E-Tran.

2.3.5 Contingencies

The contingency lists for the three islands were provided by Hawaiian Electric Transmission Planning. Contingencies were sorted into priority and non-priority contingencies, with study focus being on the priority contingencies.

2.3.5.1 Oahu Contingencies

17 contingencies were simulated for Oahu:

- 12 3-phase faults with primary clearing and reclosing
- 2 SLG delayed clearing faults
- 13 SLG faults under breaker fail conditions

2.3.5.2 Maui Contingencies

29 contingencies were simulated for Maui:

- 12 3-phase faults with primary clearing and reclosing
- 12 SLG delayed clearing faults
- 5 SLG faults under breaker fail conditions

2.3.5.3 Hawaii Island Contingencies

34 contingencies were simulated for Hawaii Island:

- 16 3-phase faults with primary clearing and reclosing
- 12 SLG delayed clearing faults
- 6 SLG faults under breaker fail conditions

2.3.6 Under Frequency Load Shedding (UFLS)

The under-frequency load shedding scheme was implemented in PSCAD in the same way it is modelled in PSS/E. The capability to read the UFLS information from the PSS/E dyr file and replicate the UFLS breakers and relays in the translated PSCAD case was added to the E-Tran translation program, allowing for the UFLS to be realized in PSCAD with no manual effort. The UFLS relays used a frequency measurement which is calculated by a phase-locked-loop component, passed through a smoothing function with a 15-cycle time constant. The UFLS, when activated, also trips all DER generators which are connected to the load buses. Figure 2.2 shows an example of how the UFLS was implemented in PSCAD.

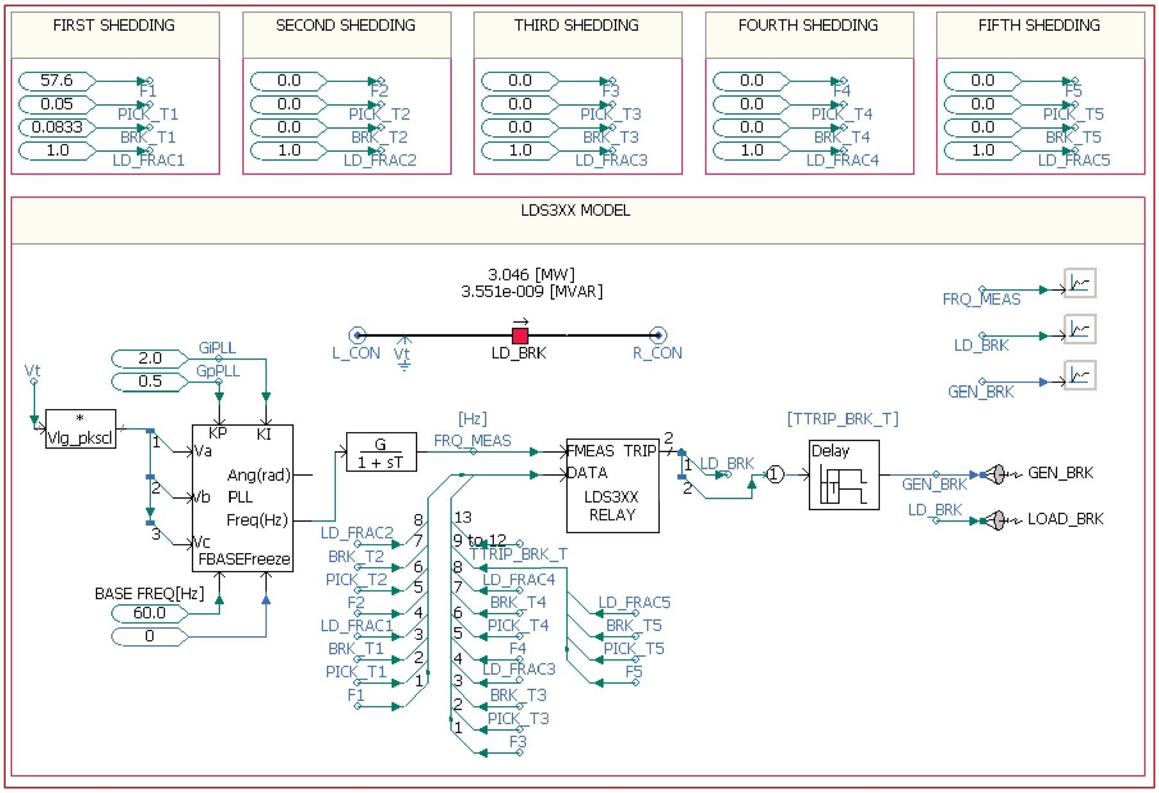

Figure 2.2: UFLS implementation example in PSCAD.

2.3.7 Distributed Energy Resources (DER)

Distributed Energy Resources (DERs) or Distributed Generation (DG) was modelled at most of the distribution buses in the three island systems. These generators supplied close to half of the system load in the studied dispatch scenarios. The DER was modelled using a generic 3-phase PV inverter model in PSCAD[3]. The generic DER PV inverter which was used had the following features:

- Phase-locked-loop to measure the system phase angle and frequency
- Inner current control loops
- Outer real and reactive power control loops
- Voltage and frequency protection thresholds matching with the PSS/E models
- Real and reactive current blocking due to undervoltage
- Average-voltage source interface to the system
- Inverter transformer with typical ratings
- Inverter filters

[3] Note that 3-phase DER models were used to improve simulation speed over the use of single-phase models. This approximation may impact the extent of DER resource which would block during single phase faults.

95% of the DER by MW capacity was modelled using the detailed generic model described above. The remaining DER was modelled using a Thevenin equivalent passive model (voltage source behind a high-impedance). This was done to reduce the complexity and computational requirement of the PSCAD case.

All DER were configured to be controlling the reactive power at the high side of the inverter transformer in all operating conditions. The DER active and reactive current references were set to go to zero (block) for undervoltages. It should be noted that the DER performance was very sensitive to these blocking thresholds, and that the values chosen may be conservative. However, no delay was modelled between when voltage recovered above the block threshold and when the DER resource resumed producing current following momentary cessation, which would further degrade performance.

Three variations of protection settings were implemented in the PSCAD models, two of which (P1 & P2) represent legacy DERs with sensitive trip settings and one of which (P3) represents modern DERs with trip settings close to those required in IEEE 1547-2018. A comparison of the protection settings is listed in Table 2.10.

Table 2.10: DER Protection Settings

Setting	P1	P2	P3
UV pickup setting 1 (pu)	0.88	0.88	0.88
UV time delay 1 (s)	1.99	1.99	19.99
UV pickup setting 2 (pu)	0.5	0.5	0.7
UV time delay 2 (s)	0.157	0.157	9.99
UV pickup setting 3 (pu)	unused	unused	0.5
UV time delay 3 (s)			0.49
OV pickup setting 1 (pu)	1.1	1.1	1.1
OV time delay 1 (s)	0.99	0.99	0.91
OV pickup setting 2 (pu)	1.2	1.2	1.2
OV time delay 2 (s)	0.157	0.157	0.157
UF pickup setting 1 (Hz)	59.3	57	57
UF time delay 1 (s)	0.157	0.157	19.99
UF pickup setting 2 (Hz)	unused	unused	56
UF time delay 2 (s)			0.157
OF pickup setting 1 (Hz)	60.5	60.5	63
OF time delay 1 (s)	0.157	0.157	19.99
OF pickup setting 2 (Hz)	unused	unused	64
OF time delay 2 (s)			0.157

2.4 Study Dispatch Scenarios

The study dispatch scenarios considered were severe dispatch scenarios with very high penetration of renewable generation and few synchronous resources online (~5% of total generation from synchronous resources). These dispatch scenarios were provided by Hawaiian Electric Transmission Planning. A single dispatch scenario was considered for Maui and Hawaii Island, while a severe and a less-severe dispatch scenario was considered for Oahu.

2.4.4 Oahu Dispatch

Table 2.11: Oahu PSCAD study dispatch scenario - Severe

	Pmax	Pmin	Unit MVA	Pgen	up reg (spin)	down reg
Synchronous Units	68.5	35.0	117.1	52.7	15.8	17.7
				Pgen	%CF	
Wind	123	0		23.3	19%	
				Pgen	Net	up res
PV	540	0		515.4	427.5	208.4
ESS	557	-557		-87.9		
				Pmax	Pgen	%CF
Central PV				540	427.5	79%
DG-PV				661	554	84%
Total Kinetic Energy					352	
Total Load					1057	
Total Thermal Generation					53	
Total Renewable Generation					1005	
Total Generation					1057	
Excess Generation					0	
Legacy DG-PV			73.5	59.3Hz Output		61.5
			215.9	60.5Hz Output		180.8

Table 2.12: Oahu PSCAD study dispatch scenario – Less Severe

	Pmax	Pmin	Unit MVA	Pgen	up reg (spin)	down reg
Synchronous Units	276.5	145	416.6	160.8	115.7	15.8
				Pgen	%CF	
Wind	123	0		23.3	19%	
				Pgen	Net	up res
PV	540	0		515.4	489.2	365.5
ESS	557	-557		-26.2		
				Pmax	Pgen	%CF
Central PV				540	489.2	91%
DG-PV				661	554	84%
Total Kinetic Energy					2248	
Total Load					1065	
Total Thermal Generation					208	
Total Renewable Generation					856	
Total Generation					1065	
Excess Generation					0	
Legacy DG-PV			73.5	59.3Hz Output		61.5
			215.9	60.5Hz Output		180.8

2.4.5 Maui Dispatch

Table 2.13: Maui PSCAD study dispatch scenario

	Pmax	Pmin	Unit MVA	Pgen	up reg (spin)	down reg
Synchronous Units	12.3	7.9	44.8	7.9	4.4	0.0
				Pgen	%CF	
Wind	72	0		2.1	2.9%	
				Pgen	Net	up reg
PV	148	0		140.3	65.3	115
ESS	175	-175		-75		
				Pmax	Pgen	%CF
Central PV				148	140.3	95%
DG-PV				129.8	82.8	64%
Total Kinetic Energy					123	
Total Load					158	
Total Thermal Generation					8	
Total Renewable Generation					190	
Total Generation					158	
Excess Generation					0	
Legacy DG-PV			7.2	59.3Hz Output		4.6
			76.7	60.5Hz Output		49.0

2.4.6 Hawaii Island Dispatch

Table 2.14: Hawaii Island PSCAD study dispatch scenario

	Pmax	Pmin	Unit MVA	Pgen	up reg (spin)	down reg
Synchronous Units	54.6	22	71.6	32.3	14	2
				Pgen	%CF	
Wind	31	0		15.3	49%	
				Pgen	Net	up reg
PV	124.1	0		120	60	60
ESS	120	-120		-60		
				Pmax	Pgen	%CF
Central PV				124.1	120	97%
DG-PV				127.7	92	72%
Total Kinetic Energy					209	
Total Load					199	
Total Thermal Generation					24	
Total Renewable Generation					176	
Total Generation					200	
Excess Generation					0	
Legacy DG-PV			5.2	59.3Hz Output		4.6
			76.7	60.5Hz Output		49.0

2.5 Overall Statistics on Models

Table 2.15: Table of Overall Statistics on Models

Island	Number of Buses	Number of utility-scale renewable plants	Number of DER inverters	Number of Parallel PSCAD Cases	Number of load buses with UFLS	Number of Synchronous Machines	Time required to run 30 second simulation on 64 core computer (hours)
Oahu	271	21	165	77	53	2 / 6	7
Maui	245	13	123	59	29	3	5
Hawaii Island	239	6	162	67	45	3[4]	5

2.6 Performance Criteria

The primary study objective was to determine whether the island systems retain stability during priority contingencies and whether loss of load is avoided. Towards this objective, the performance of the Stage 1 and 2 plants and other key plants were analyzed with this general performance criteria:

1. Stage 1 and 2 plants should not trip unnecessarily during or after the contingency.
2. Load should not be shed.
3. System should ultimately stabilize with no undamped oscillations, voltage or frequency excursions outside of nominal ranges.
4. In the event of a post-fault under-frequency and/or under-voltage caused by DER tripping/blocking, key plants should contribute to frequency support and voltage support in a fast and stable manner, where the desired speed of response is dependent on the system needs as observed in study results. For grid-forming BESS inverters, there should be a near-immediate active power response to compensate for the generation mismatch caused by DER tripping/blocking. Ideally, key plants should be operating at or near their respective current limits for this condition until voltage and frequency return to near nominal value.
5. Since this study was primarily concerned with overall island stability, in some cases relatively minor issues or issues with smaller or less consequential plants were considered acceptable for the sake of focusing on the most severe issues. However, these issues are still reported and further work may be done to optimize performance.

2.7 Additional Assumptions

To improve simulation efficiency or due to insufficient available data, the following additional assumptions were made:

1. The PSCAD simulations were run with a simulation time step of 15 µs in the AC system case for all three islands. Each individual project parallel case ran with the time step required by the PSCAD model in that case. The PSCAD snapshot feature was not used in the simulations as some models do not support this feature.
2. Transformer saturation was not enabled in the study cases.

[4] PGV and two small hydro plants

3. Transmission lines were modelled as Bergeron travelling-wave line models where possible. Frequency-dependent line models were not developed.
4. Surge Arresters or Metal Oxide Varisters (MOVs) were not modeled in any of the simulations

3 Results and Discussion

The following sections report the study results for each of the islands. Where applicable, results before and after project control tuning are reported separately. Table 3.1 gives a high-level results summary for all three islands.

Table 3.1: High-Level Study Results Summary

Island	Results Summary		
	Grid-Following Stage 2 BESS	Grid-Forming Stage 2 BESS: pre-tuning	Grid-forming Stage 2 BESS: post-tuning
Oahu - Severe Dispatch	N-0 condition is not stable. System voltage collapses when temporary fault applied at bus 330. No additional faults were examined.	N-0 condition is stable. System frequency very quickly drops when temporary fault is applied at bus 330, leading to UFLS and many plants tripping. No additional faults were examined.	N-0 condition is stable. System response to temporary fault at bus 330 is improved but still not acceptable. No additional faults were examined.
Oahu - Less Severe Dispatch	N-0 condition is stable. Instability and load-shedding observed for all priority contingencies.	N-0 condition is stable. 4 of 11 priority contingencies result in instability and significant load-shedding	System performance improved substantially. 3 of 27 contingencies result in relatively minor load shedding
Maui	N-0 condition is not stable, growing oscillations lead to UFLS. No additional faults were examined.	N-0 condition is stable. Load shedding and minor instabilities observed in several priority contingencies	System performance improved substantially. No UFLS observed for any contingency and no instabilities were observed.
Hawaii Island	N-0 condition is stable. UFLS and instability observed for 6 of 16 priority contingencies	Some improvement in results is observed, as just 4 of 16 priority contingencies have UFLS and instabilities.	Three priority contingencies result in instability and load shedding, two of which are loss of critical large generators

3.1 Oahu

3.1.1 Grid-Following Results – Severe Dispatch

The Oahu N-0 system displayed large sustained oscillations when using the grid-following inverters for Stage 2 BESS projects. Furthermore, the system voltage collapsed entirely when a typical temporary fault was applied. Because of these results, the severe system dispatch was considered to be an unviable dispatch when using GFL controls. The following Oahu results sections focus on using GFM controls for the Stage 2 BESS projects.

3.1.2 Grid-Forming Results – Severe Dispatch

The N-0 condition for the severe dispatch case shows a stable result when the grid-following inverters for the Stage 2 BESS projects (with limited exceptions) were replaced by the grid-forming models. However, when a typical temporary fault is applied at bus 330, the system is unable to recover to nominal voltage and frequency for more than 10 seconds, but does eventually recover with the help of load-shedding. No additional faults cases were examined in the severe dispatch as it was clear from the temporary fault scenario that additional control tuning and/or grid support devices are needed in order to make this dispatch viable.

3.1.3 Grid-Following Results – Less Severe Dispatch

The less severe case was stable in the N-0 condition when using grid-following inverters for the Stage 2 BESS projects. However, significant loss in load was observed in all of the priority contingencies studied due to the lack of fast inertial support from the Stage 2 plants.

3.1.4 Grid-Forming Results – Less Severe Dispatch, Pre-Tuning

Switching the Stage 2 BESS projects to use grid-forming controls leads to reduced load shedding in all of the priority contingencies. However, some of the contingencies showed Stage 1 and 2 plants which were not stable after fault clearing, as noted in the following results tables.

Table 3.2: Oahu Table of Study Results (priority faults only, less-severe dispatch, pre-tuning)

Cont. ID	Load tripped (MW)	DER tripped (MW)	Existing IBR tripped (MW)	Notes
C3	0	0	≈10	2, 5
C10	≈160	≈200	≈35	1, 2, 3, 4, 5
C11	0	0	≈10	2, 5
C13	≈20	≈110	≈20	1,2, 3, 5
C14	0	0	≈10	2, 5
C15	0	0	≈10	2, 3, 5
C16	≈230	≈210	≈80	1,2, 3, 4, 5
C20	0	0	≈10	2, 3, 5
C21	≈300	≈190	≈35	1, 2, 3, 4, 5
C25	≈220	≈240	≈10	1, 2, 3, 4, 5
C26	0	0	≈10	1, 2, 5

Table 3.3: Table of Notes referred to in Oahu Study Results Table (less-severe dispatch, pre-tuning)

Note #	Note Description
1	DER blocks due to undervoltage, and stays blocked because system voltage doesn't recover past the unblocking threshold. Stage 1 and 2 plants are not contributing significantly to voltage control because voltage controllers are set too passively.
2	Some GFM BESS have a slow undamped oscillation against system, frequency ranges between 0.1 Hz and 1 Hz.
3	Some or all Stage 1 & 2 plants using specific inverter controls lose control of active and/or reactive power during fault recovery, which contributes to loss of load.
4	Project's BESS shows an uncontrolled active and reactive power swing during fault recovery, which contributes to loss of load.
5	One or more Existing IBR plants tripped.

3.1.5 Grid-Forming Results – Less Severe Dispatch, Post-Tuning

After several iterations of control tuning of Stage 1 and 2 plants, the grid-forming system model showed significant improvement. Appendix A contains specific setting recommendations for each project. Tuning recommendations were not confirmed by the developers for this study and should be verified by the developers for future studies. Only two of the priority contingences show load shedding after project tuning. Table 3.4 shows these results in more details.

Table 3.4: Oahu Table of Study Results (less-severe dispatch, post-tuning)

Cont. ID	Load tripped (MW)	DER tripped (MW)	Existing IBR tripped (MW)	Notes
C1	0	≈60	≈10	1, 2
C2	≈90	≈190	≈80	1, 2,5
C3	0	≈60	≈10	1, 2
C4	0	≈170	≈80	1, 2,5
C5	0	≈60	≈10	1, 2
C6	0	≈60	≈80	1, 2
C7	0	≈60	≈10	1, 2
C8	0	≈60	≈80	1, 2
C9	0	≈60	≈10	1, 2
C10	0	≈155	≈80	1, 2, 3, 4
C11	0	0	≈10	1, 2
C12	0	≈60	≈10	1, 2
C13	0	≈60	≈20	1, 2
C14	0	≈60	≈10	1, 2
C15	0	≈170	≈10	1, 2
C16	0	≈60	≈80	1, 2
C17	0	≈60	≈10	1, 2
C18	0	≈60	≈10	1, 2
C19	0	≈130	≈80	1, 2
C20	0	0	≈10	1, 2
C21	0	≈60	≈80	1, 2
C22	0	0	≈10	1, 2
C23	0	≈140	≈80	1, 2
C24	0	≈60	≈10	1, 2
C25	≈45	≈170	≈125	1, 2, 3
C26	0	≈60	≈10	1, 2
C27	≈115	≈170	≈10	1, 2,5

Table 3.5: Table of Notes referred to in Oahu Study Results Table (less-severe dispatch, post-tuning)

Note #	Note Description
1	Some GFM Batteries have a slow undamped oscillation against system, frequency of oscillation ranges between 0.1 Hz and 1 Hz.
2	One or more Existing IBR plants tripped.
3	Project's Battery initial dispatch is favorable for frequency response/loss of load (dispatched at 100% charging).
4	Plants with specific inverters decrease reactive power below pre-fault level during fault recovery when system voltage is less than 0.9 pu. The LVRT voltage controller may not be working correctly.
5	Project's BESS shows an uncontrolled active and reactive power swing during fault recovery, which contributes to loss of load.

3.1.6 Plots and Discussion of Specific Issues

3.1.6.1 Instability in grid-following severe dispatch case

Figure 3.1 shows the oscillatory behaviour observed in the N-0 severe dispatch when using the grid-following BESS inverters. When a typical temporary fault is applied at the bus 330, the system voltage collapses and all of the UFLS is triggered. Figure 3.2 shows the plots of a project BESS for this contingency.

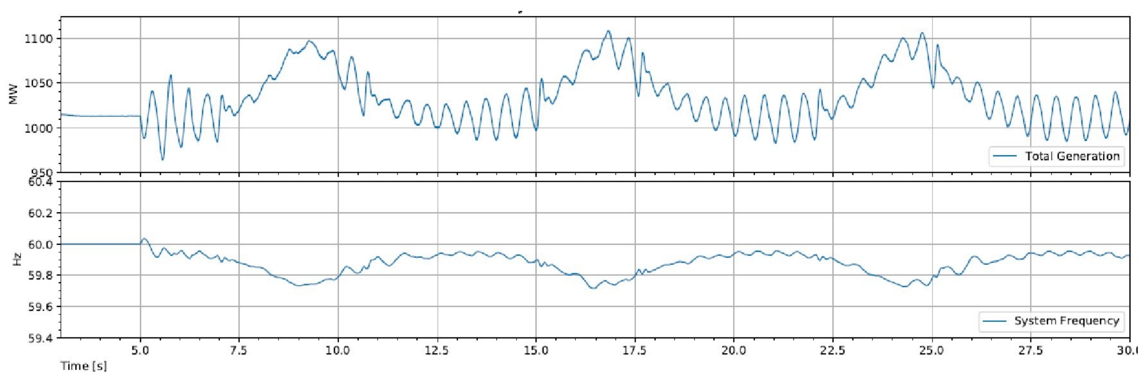

Figure 3.1: Sustained oscillation in the Oahu Severe Dispatch N-0 grid-following case.

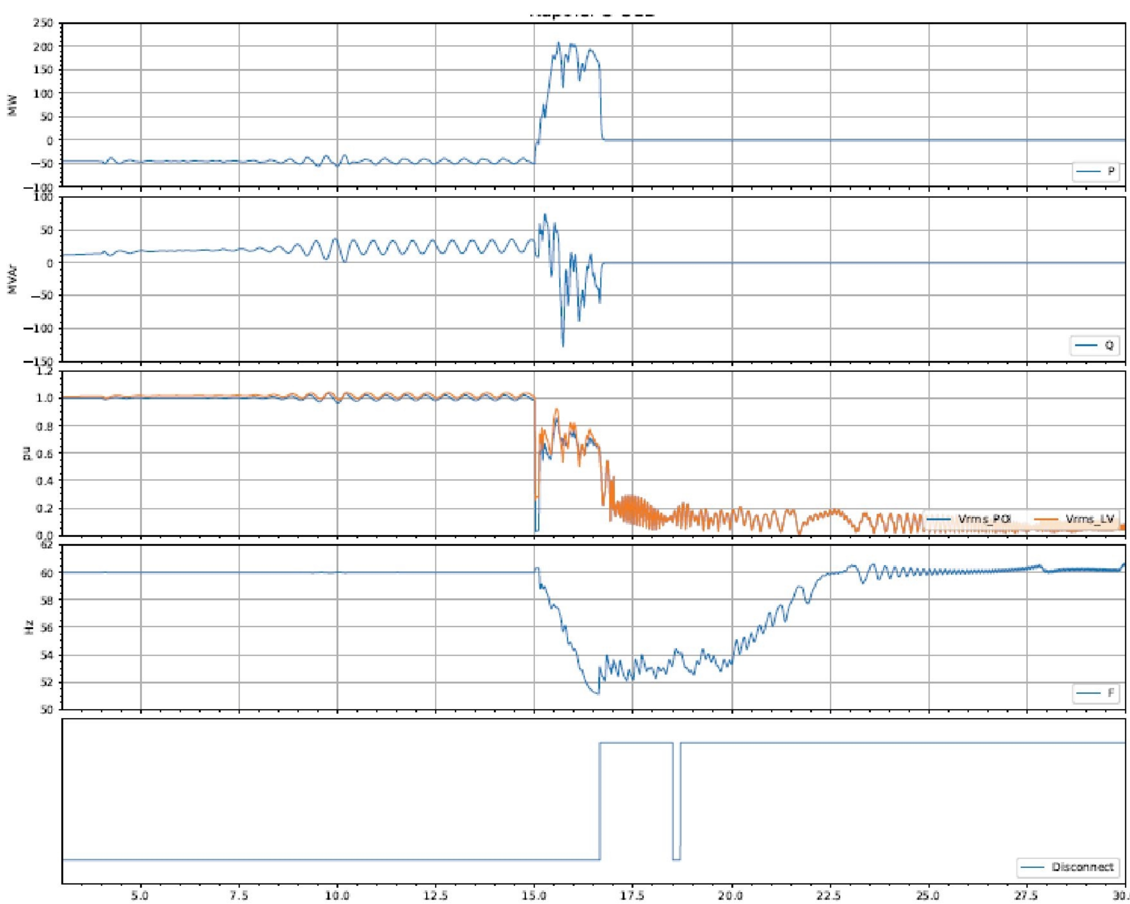

Figure 3.2: Project's BESS traces for Oahu Severe Dispatch temporary fault grid-following case. The system voltage collapses shortly after fault clearing.

3.1.6.2 Undervoltage and Underfrequency in grid-forming severe dispatch

When a typical temporary fault is applied at the bus 330 in the grid-forming severe dispatch case, DER blocking results in the post-fault voltage only recovering to below the un-block threshold of the DER. Because of the generation deficiency, frequency drops to 59 Hz. This system-wide undervoltage and underfrequency condition is sustained for several seconds, during which time certain Stage 1 and 2 plants (all using grid-following controls in this scenario) do not contribute substantially to voltage or frequency control. This condition eventually results in several stages of UFLS before the system recovers to nominal voltage and frequency. UFLS system totals are shown in Figure 3.3, and the response from a representative plant is shown in Figure 3.4. The response from this plant is typical of all the Stage 1 and 2 plants using a specific type of inverters. This figure highlights two concerns with the LVRT controller:

1. Certain plant inverters do not have an inverter-level frequency/watt controller and the inverters hold the pre-fault active current when in ride-through mode, regardless of frequency. This results in an active power output proportional to the undervoltage.
2. Certain plant inverters need to have more aggressive volt/var settings in order to inject more reactive power and thereby increase the system voltage. However, aggressive volt/var settings have been

observed to cause the inverters to become unstable following fault clearing in some cases, possibly leading to a further reduction in frequency and voltage.

The use of grid-forming BESS equipment can overcome these control challenges because grid-forming controls inherently have the ability to provide fast and stable frequency and voltage control by holding the magnitude and phase of the terminal voltage constant.

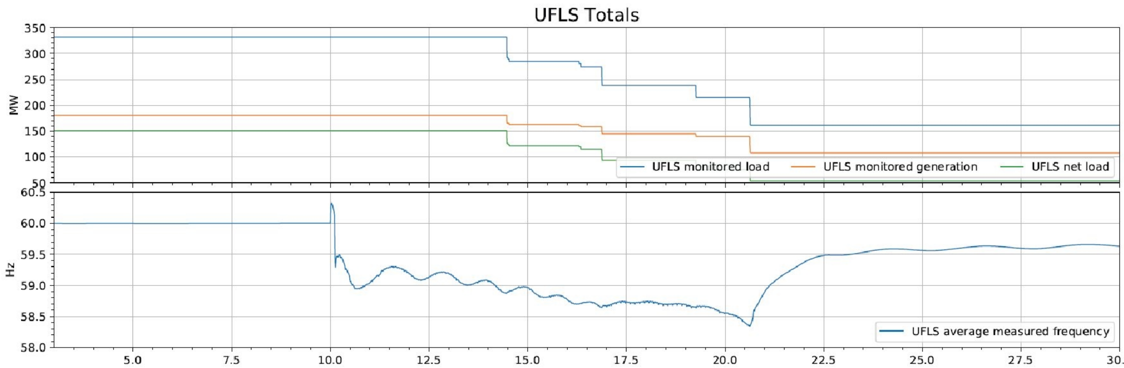

Figure 3.3: System UFLS totals for simple temporary fault in the Oahu grid-forming severe dispatch case. System frequency is low for longer than 10 seconds.

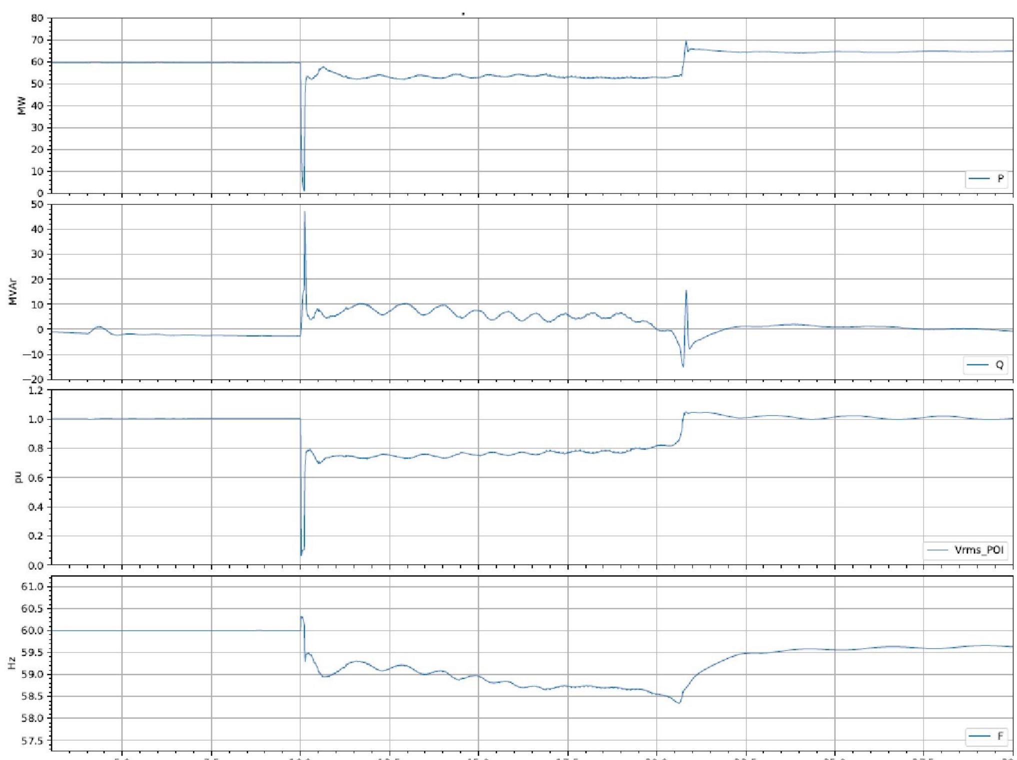

Figure 3.4: Plant response to simple temporary fault in the Oahu grid-forming severe dispatch case. Note that there is not a substantial response to system undervoltage and underfrequency.

3.1.6.3 DER blocking and delayed voltage recovery

Several pre-tuning cases showed that all of the DER stays blocked after fault clearing because the voltage does not recover past the un-block threshold, leading to a net deficiency of generation and UFLS. This issue was also present on Maui, and is discussed further in 3.2.4.2. On Oahu, this issue was caused primarily by a number of Stage 1 and 2 plants which did not behave in a controlled manner after fault clearing. This issue was mitigated in the grid-forming less-severe dispatch case after the behaviour of these plants was corrected.

3.1.6.4 System-wide oscillations

Sustained oscillations were observed in many of the pre and post-tuning cases. The frequency of these oscillations ranged from very low < 0.05 Hz up to 1 Hz, and was generally higher when a significant amount of DER was tripped. This issue was also present on Maui, and is discussed further in 3.2.4.3.

3.1.6.5 Individual plant tuning

The pre-tuning grid-forming study results for the less-severe dispatch showed that several or all of the Stage 1 and 2 plants using certain inverters did not contribute to voltage and/or frequency control in a stable manner after fault clearing, as shown in the traces for C10 in Figure 3.5 below. Through discussions with the manufacturer, several settings were identified which were not set appropriately for weak system performance.

After several rounds of control tuning, a stable response was achieved from these plants in the less-severe dispatch case (see Figure 3.6). However, more control revision may be necessary for these plants, as there is substantial inverter capability which is left unused during undervoltage and underfrequency conditions as noted in 3.1.6.2.

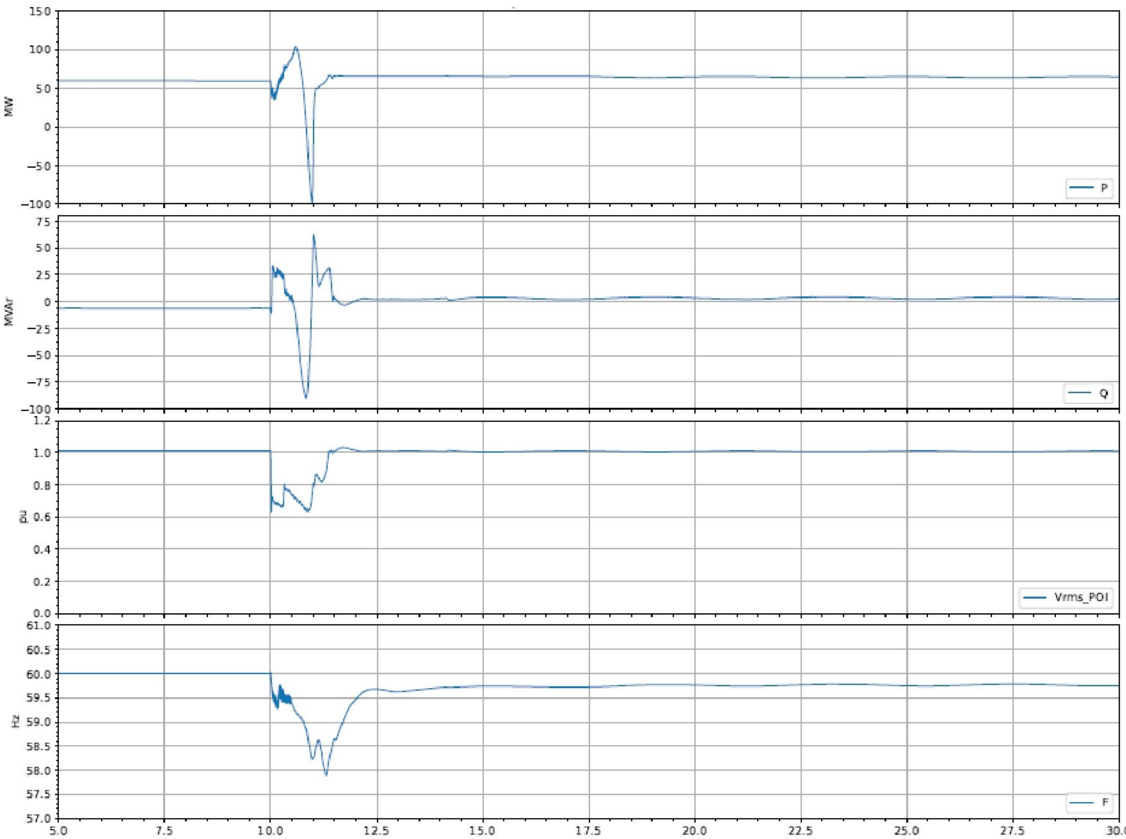

Figure 3.5: Plant response (pre-tuning) to C10 in the Oahu grid-forming less-severe dispatch case. Note the inappropriate sudden decrease in active and reactive power shortly after fault clearing leading to UFLS operation.

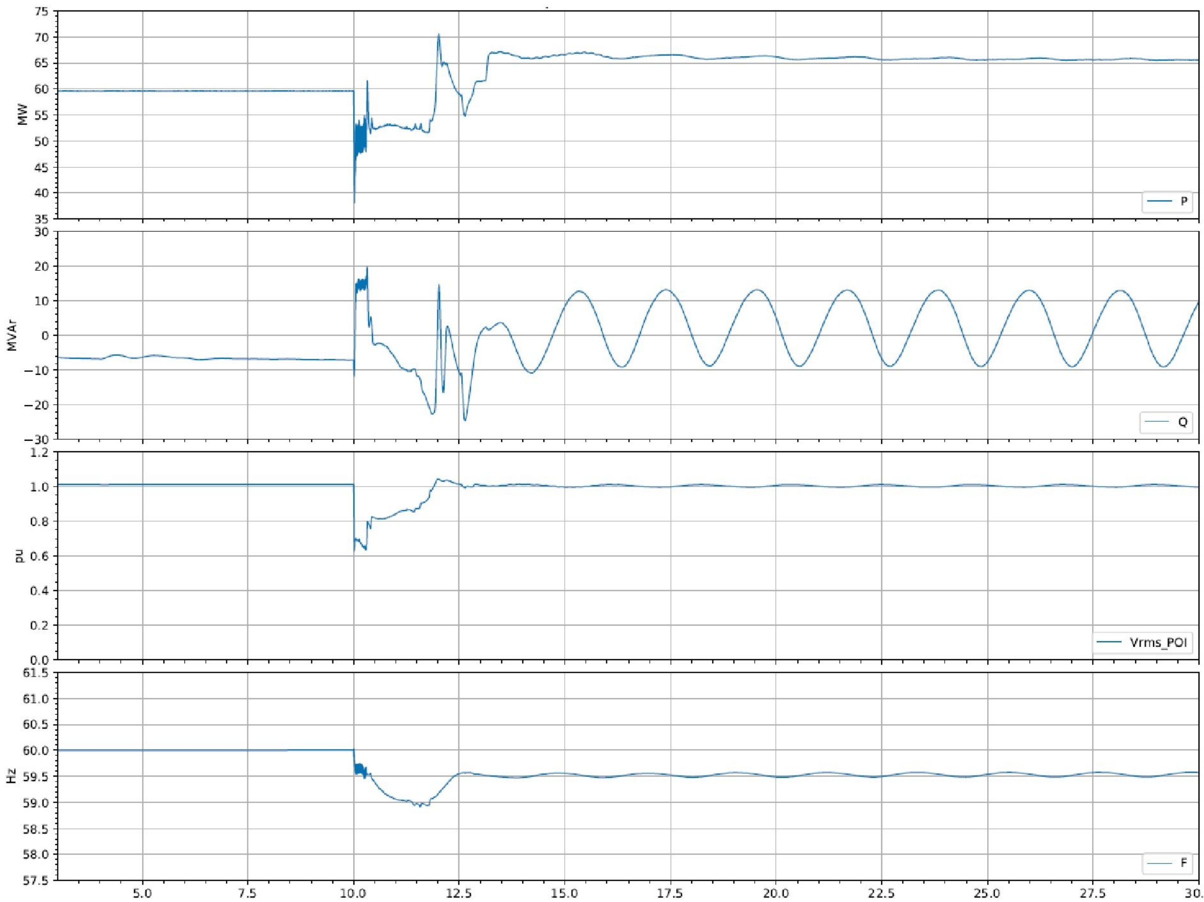

Figure 3.6: Plant response (post-tuning) to C10 in the Oahu grid-forming less-severe dispatch case. Note that the active and reactive power is much more stable than in the pre-tuning result (no load shed). Also note undamped oscillations.

3.1.6.6 BESS uncontrolled behaviour during fault recovery in post-tuning cases

Contingencies C2 and C27 (SLG breaker-fail cases) result in a steep reduction of the active and reactive power output from certain GFM BESS inverters, as shown in Figure 3.7. Similar behaviour was observed in several of the pre-tuning cases, which were mitigated by adjusting the thresholds at which the BESS inverters exit a current-limiting ride-through mode. This issue may be mitigated by either further tuning the mode-transition thresholds or implementing other control strategies which soften the transition between control modes.

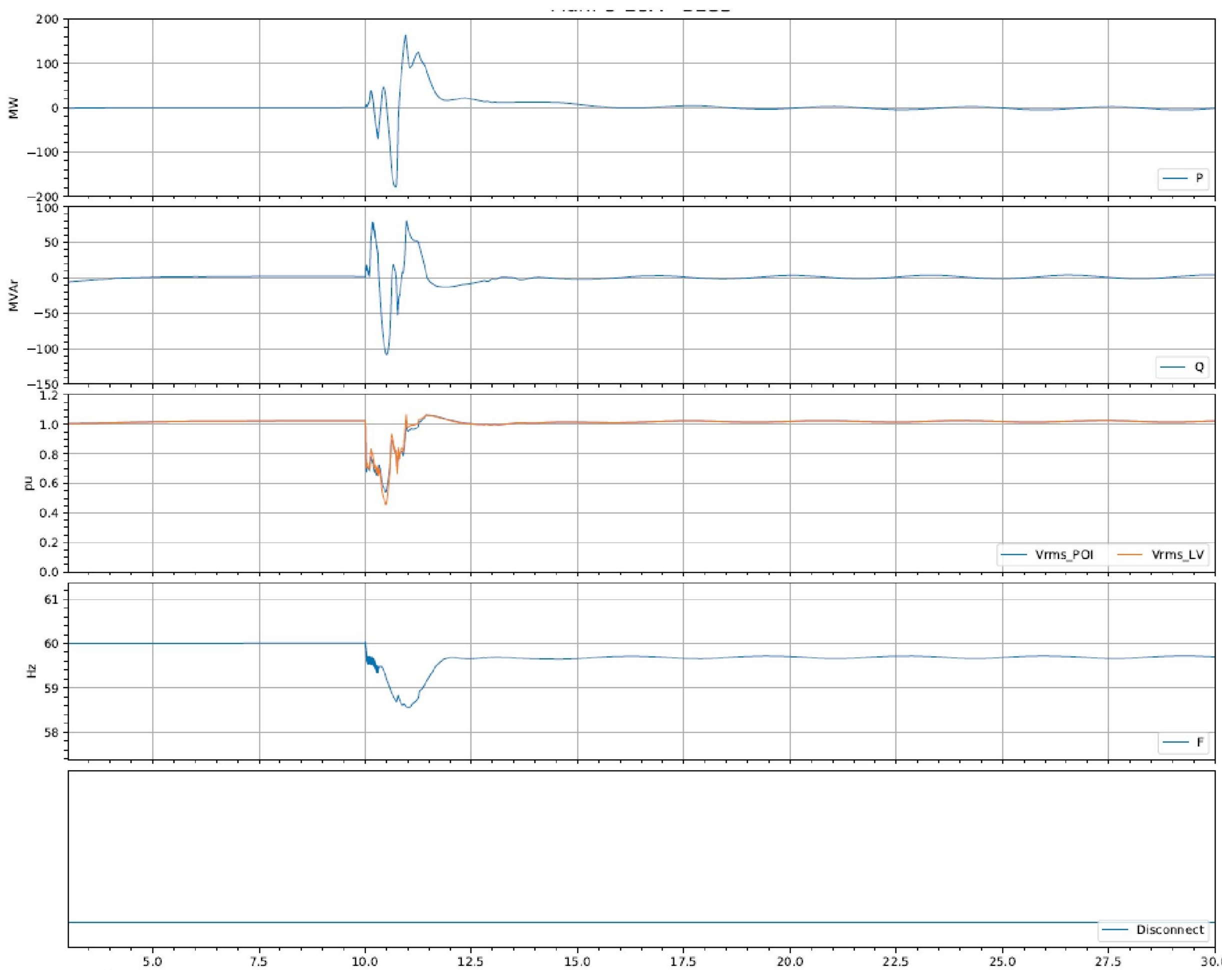

Figure 3.7: Project's BESS inverter response to C2. Note the inappropriate reduction in active and reactive power during fault recovery resulting in UFLS operation.

3.1.6.7 Existing plant tripping

As noted in Table 3.8, many of the existing IBR plants were observed to trip during contingency events. In many cases, the plants tripped due to self-induced over or under voltage conditions at the terminals. The tripping events may be occurring due to modelling issues as many of the models used for existing plants are old and may not reflect the as-built plant behaviour, but the system is also weak and the controller vintages of these plants are prone to tripping in weak grids, and tripping of existing IBRs has been observed in operations. Study results may improve if fewer existing IBR plants trip.

3.2 Maui

3.2.1 Grid-Following Results

The N-0 Maui system was not stable when using the grid-following BESS inverters for Stage 2 projects. A growing oscillation was observed which led to load shedding. No additional faults cases were examined as this was considered to be an unviable dispatch when using the grid-following BESS inverters.

3.2.2 Results Table: Grid-Forming, Pre-Tuning

Switching to the grid-forming BESS inverters for the Stage 2 projects (both stand-alone and PV-plus-BESS applications) stabilized the N-0 case, however a significant amount of load shedding was observed for priority contingencies as detailed in the table below.

Table 3.6: Maui Table of Study Results (priority contingencies only, pre-tuning)

Contingency ID	Load tripped by UFLS (MW)	DER tripped (MW)	Notes
C2	40	45	1, 2
C3	0	0	3
C7	0	0	3
C8	12	45	1, 3, 4, 5
C9	0	0	3
C10	0	8	3
C15	0	0	3, 6
C16	12	50	1, 3, 4, 5, 7
C20	10	50	1, 2, 3, 8
C21	0	0	3
C22	0	40	1, 3, 5, 9
C25	40	55	1, 2, 3
C26	45	35	1, 2, 3

Table 3.7: Table of Notes referred to in Maui Study Results Table (pre-tuning)

Note #	Note Description
1	DER blocks due to undervoltage, and stays blocked because system voltage doesn't recover past 0.9. IBRs are not contributing much to voltage control because (probably) they have too much droop on their voltage controllers. Recommend to increase VAR output for nominal undervoltages.
2	Plant doesn't control frequency correctly and reduces active power into an underfrequency, causing several stages of UFLS to trigger.
3	Some GFM Batteries have a slow oscillation against system, undamped, frequency ranges between 0.1 Hz and 1 Hz.
4	Frequency falls due to DER tripping, Stage 1 and 2 plants respond but not enough to prevent partial UFLS triggering.
5	Plant trips due to underfrequency (bad protection setting, fixed in post-tuning cases).
6	Certain plants reduce active power by 7 MW after the fault, leading to slight underfrequency which the other plants can meet.
7	Plant active power recovery is sluggish (e.g. 5 seconds).
8	Plant active power instability is causing a mirrored response from other GFM. GFM controllers are holding total power.
9	Certain plants transiently loop real and reactive power between the two plants.

3.2.3 Results Table: Grid-Forming, Post-Tuning

An effort to improve the performance of Stage 1 and Stage 2 plants by control tuning was useful in mitigating UFLS triggering. Appendix A contains specific setting recommendations for each project. Tuning recommendations were not confirmed by the developers for this study and should be verified by the developers for future studies. Several issues remain outstanding, primarily that there are oscillations present whenever a significant amount of DER generation trips, as shown in Table 3.8.

Table 3.8 Maui Table of Study Results (all contingencies, post-tuning)

Contingency ID	Load tripped by UFLS (MW)	DER tripped (MW)	Post-fault Oscillation Frequency (Hz)	Notes
C1	0	0	< 0.05	
C2	0	39	0.38	3
C3	0	0	< 0.05	
C4	0	45	0.35	3
C5	0	0	< 0.05	
C6	0	18	0.3	3
C7	0	0	< 0.05	
C8	0	47	0.35	3
C9	0	0	< 0.05	
C10	0	7	< 0.05	
C11	0	0	< 0.05	
C12	0	33	0.3	3
C13	0	0	< 0.05	
C14	0	8	< 0.05	1
C15	0	0	< 0.05	
C16	0	47	0.35	3
C17	0	0	< 0.05	
C18	0	3	< 0.05	1
C19	0	0	< 0.05	
C20	0	47	0.35	3
C21	0	0	< 0.05	
C22	0	25	0.23	3
C23	0	0	< 0.05	
C24	0	3	< 0.05	
C25	0	47	0.55	2, 3
C26	0	8	0.225	3
C27	0	2	< 0.05	
C28	0	0	< 0.05	1
C29	0	2	< 0.05	1

Table 3.9: Table of Notes referred to in Maui Study Results Table (post-tuning)

Note #	Note Description
1	Certain plants continue to inject large amounts of reactive power after fault clearing, causing a voltage of 1.2 at the inverter terminals which decays to nominal levels over 5 seconds.
2	Project's BESS units trip due to a marginal undervoltage condition (< 0.7 pu for > 0.7 seconds). Before tripping, active and reactive power swings in an uncontrolled manner. Lowering a threshold at which the inverter returns from a current limiting mode may resolve this issue.
3	Some GFM Batteries have a substantial slow undamped oscillation against system, of a frequency as stated in the table.

3.2.4 Plots and Discussion of Specific Issues

3.2.4.1 N-0 instability in grid-following case

Figure 3.8 shows a growing oscillation in the total generation which leads to load shedding. This type of oscillation is caused by a high penetration of inverter-based generation with too few stabilizing devices (synchronous machines, synchronous condensers, grid-forming inverters).

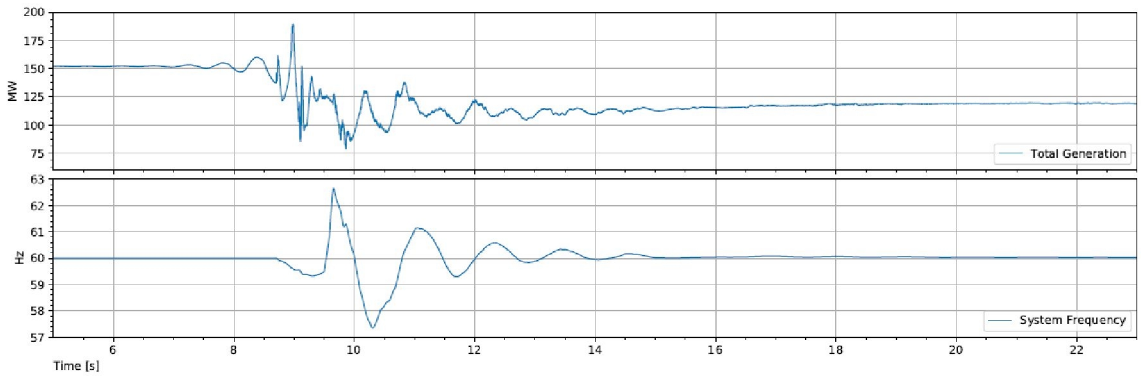

Figure 3.8: Growing oscillation leading to load shedding for Maui N-0 grid-following case.

3.2.4.2 DER blocking and delayed voltage recovery

Several cases in the grid-forming pre-tuning results show that all of the DER in the system stay blocked after fault clearing because the system voltage has not recovered past the threshold at which the DER un-blocks[5]. The reason the voltage remains low is because during the fault and at fault clearing, the system load which was being served by the DER is being served by transmission-level connected plants instead, which leads to a poor power factor in key regions of the system.

While the DER is blocked, the non-DER generation cannot meet the load demand, resulting in frequency slipping and eventual UFLS. This is shown in Figure 3.9 (system UFLS totals) and Figure 3.10 (representative DER traces).

This condition was mitigated by tuning the Stage 2 projects using certain inverters to provide more aggressive voltage support when the voltage is just below normal operating conditions. Some grid-forming BESS inverters also showed an instability at this partially-recovered voltage level which further contributed to the frequency

[5] Note that 3-phase DER models were used to improve simulation speed. This approximation may impact the extent of DER resource which would block during single phase faults, which could degrade system performance under some unbalanced faults. Future work may consider this impact further.

drop, which was mitigated by adjusting a threshold at which the BESS inverter returns from a current-limiting ride-through mode.

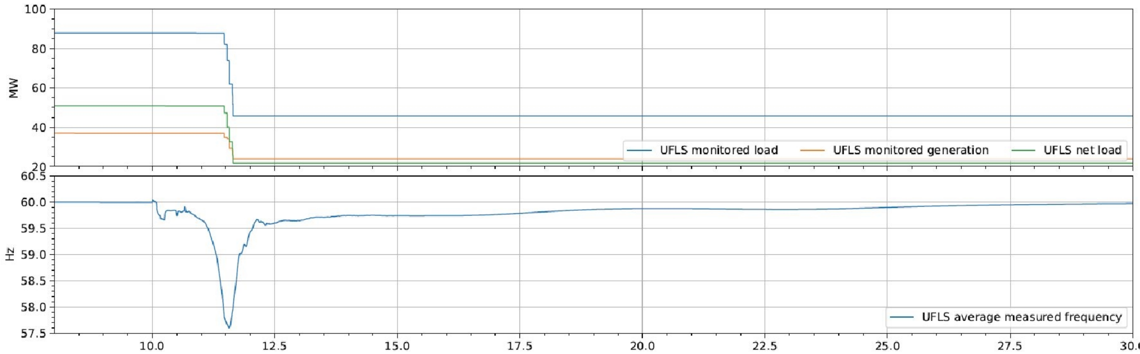

Figure 3.9: Typical system UFLS quantities during DER blocking and delayed voltage recovery (Maui) (Grid-forming, pre-tuning).

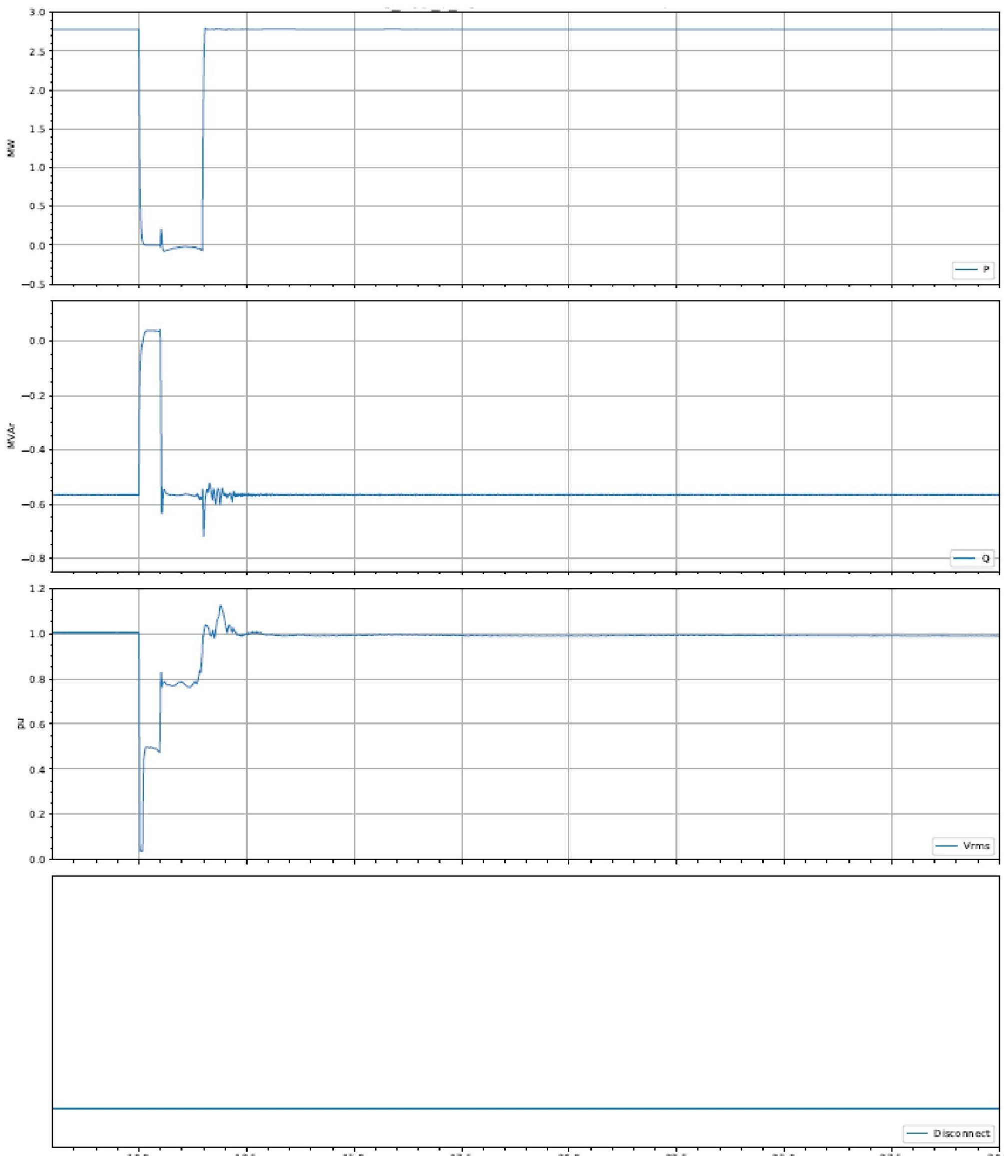

Figure 3.10: Representative DER traces during DER blocking and delayed voltage recovery (Maui) (Grid-forming case, pre-tuning).

3.2.4.3 System-wide oscillations

Sustained oscillations were observed in many of the pre and post-tuning cases. The frequency of these oscillations ranged from very low < 0.05 Hz up to 1 Hz, and was generally higher after a significant amount of DER was tripped. The frequency of oscillation for each case is noted in the post-tuning results as shown in Table 3.8. Figure 3.11 shows the system totals for a post-tuning case (C16) which clearly shows a 0.35 Hz oscillation in the Stage 2 active power total trace.

Certain BESS inverters appear to be significant contributors to these oscillations as the magnitude of oscillation is the greatest out of these, but a definitive understanding of all the contributors to the undamped oscillatory modes was not obtained. Further exploration into these oscillations and potential mitigation is required.

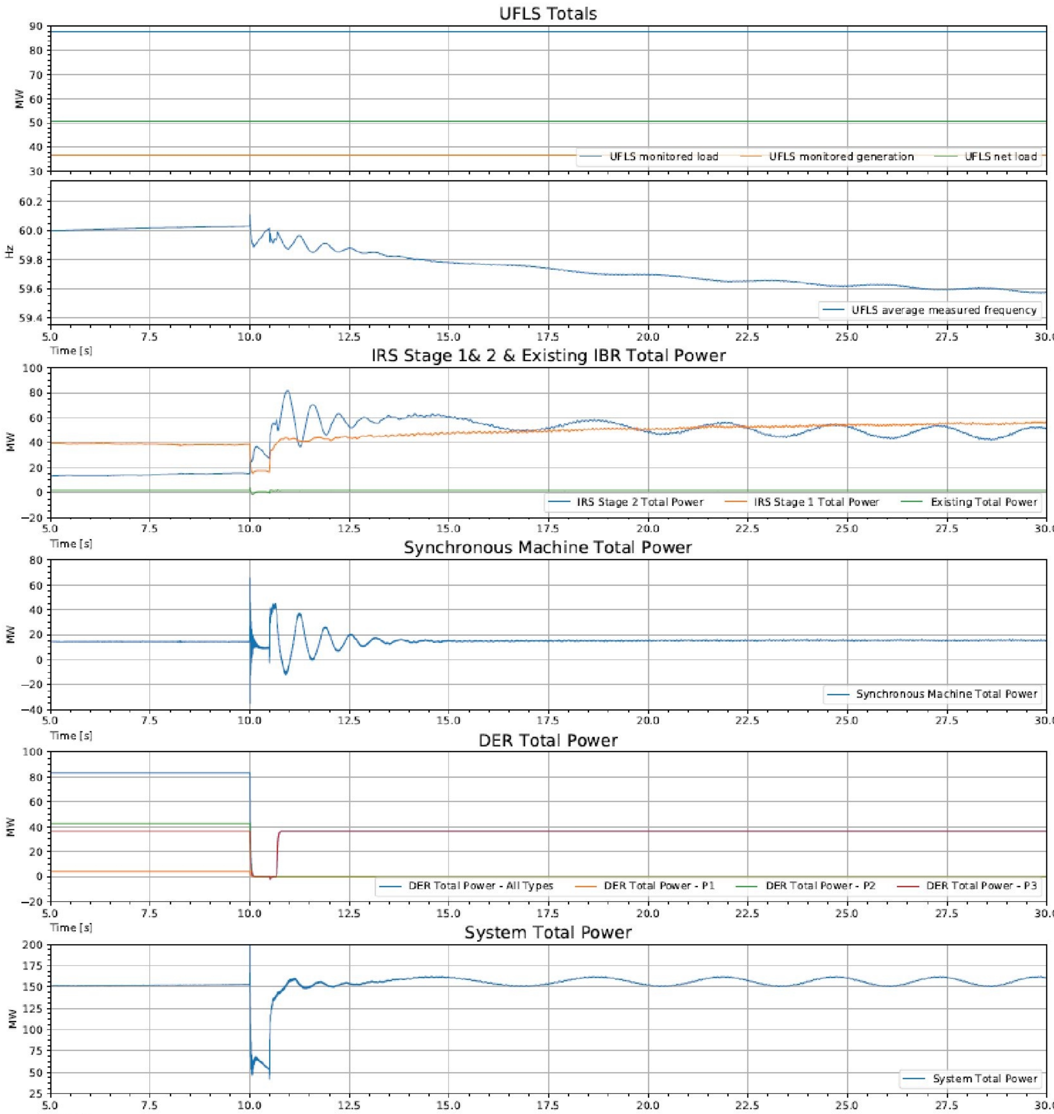

Figure 3.11: Case totals for Maui contingency 16 grid-forming post-tuning case. Note the 0.35 Hz oscillation in the Stage 2 total power trace.

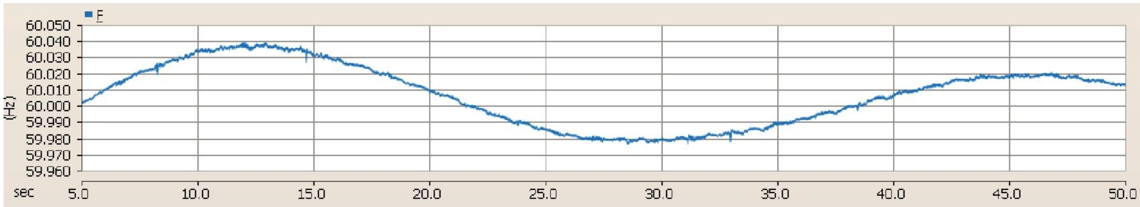

Figure 3.12: 0.03 Hz oscillation in Maui N-0 grid-forming case.

3.2.4.4 Frequency Droop Tuning

The pre-tuning results showed several cases for which UFLS occurred as a result of the overall system frequency droop being too high. Figure 3.13 shows an example of this for the C16 pre-tuning case. In this case, all of the P1 and P2 DER trip offline during the contingency, so the remaining devices need to increase their power output to make up for this lost generation. If the frequency droops are set too high, the system frequency drops to levels at which UFLS starts to activate.

Decreasing the overall system frequency droop was effective in limiting the frequency reduction caused by this contingency. Table 3.10 shows the original and tuned frequency droop settings. Note that the frequency droop setting for the certain plants was not visible in the PSCAD model and could not be changed. This results in these plants contributing much less to frequency control in the post-tuning cases than the other Stage 1 and 2 plants.

Table 3.10: Original and tuned frequency droop settings for Stage 1 and 2 plants

Plant	Original droop on export limit base	New droop on export limit base
1	3.1%	1.5%
2	3.3%	1.5%
3	3.0%	1.5%
4	1.6%	1.5%
5	1.6%	1.5%
6	2.9%	1.5%
7	5.4%	5.4%
8	5.4%	5.4%

*Plant 7 and 8 droops were experimentally determined as this setting was not visible in the configuration files, and could therefore not be altered

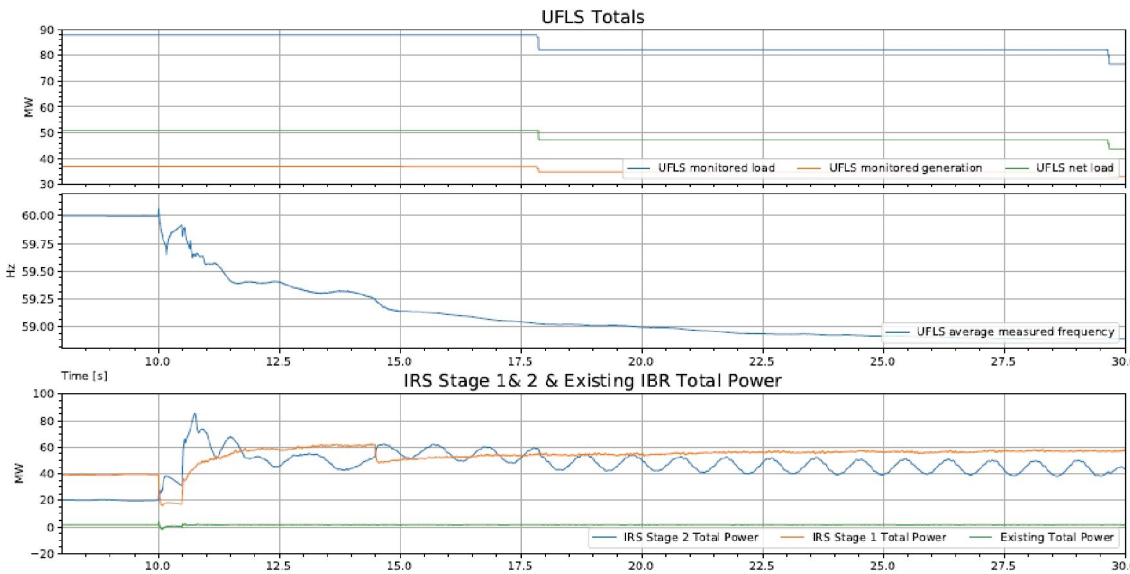

Figure 3.13: Case totals for Maui contingency 16 grid-forming pre-tuning case (prior to reduction in power/frequency droops). UFLS is triggered once at 18 seconds and again at 29.5 seconds.

3.3 Hawaii Island

3.3.1 Results Table: Grid-Following, Pre-Tuning

Table 3.11 below reports the study results for priority contingencies simulated for the Hawaii Island system. Several of these contingencies resulted in significant amount of load shedding. It is noted that loss of the large synchronous and IBR plants are significant events, and result in UFLS regardless of Stage 2 plant controls.

Table 3.11: Hawaii Table of Grid Following Study Results (priority contingencies only, pre-tuning)

Contingency ID	Load tripped by UFLS (MW)	DER tripped (MW)	Notes
C1	0	3	
C2	0	3	1
C5	0	3	1
C6	0	10	
C9	0	4	
C10	0	4	
C13	0	3	
C14	25	12	2
C18	0	0	
C19	25	35	3

Contingency ID	Load tripped by UFLS (MW)	DER tripped (MW)	Notes
C22	110	80	4
C23	0	0	
C28	75	85	5
C30	0	16	6
C31	65	53	7
C34	110	62	8

Table 3.12: Table of Notes referred to in Hawaii Grid Following Study Results Table (pre-tuning)

Notes	Description
1	BESS has a damped oscillatory response following fault clearing.
2	Long clearing time fault results in an oscillatory response in the IBRs and the synchronous machines. A power swing in the PGV plant after fault clearing causes an underfrequency, triggering some load shedding. The amount of load shedding is within the allowable limits, which is 15% of the total system load.
3	UFLS happens, followed by undamped oscillations in all generators except for DER. Governor response and IBR frequency controllers may be tuned to mitigate these oscillations. The amount of load shedding is within the allowable limits, which is 15% of the total system load.
4	Plant is unstable on reclose. UFLS results. (Fixed with Tuning).
5	Loss of largest synchronous unit. DER trips on UV. WRHPC is unstable.
6	Loss of some DER results in small steady state under frequency. Similar to case 19 (Note 4), slow voltage collapse at some busses until frequency falls out of deadband, and IBR responds to correct it.
7	Plant loses stability for a short period, resulting in a lot of UFLS. - Same instability as Case 19 (Note 5) .
8	Loss of large IBR Plant results in most of the load being lost due to UFLS.

3.3.2 Results Table: Grid-Following, Post-Tuning

An effort to improve the performance of Stage 1 and Stage 2 plants by control tuning was useful in mitigating UFLS triggering in some of the contingencies, however, several issues remain outstanding. Tuning recommendations were not confirmed by the developers for this study and should be verified by the developers for future studies.

Post-tuning simulation results are summarized in the following Table 3.13.

Table 3.13: Hawaii Table of Grid Following Study Results (priority contingencies only, post-tuning)

Contingency ID	Load tripped by UFLS (MW)	DER tripped (MW)	Notes
C1	0	3	
C2	0	3	1
C5	0	2	1
C6	0	10	
C9	0	4	
C10	0	4	
C13	0	3	

Contingency ID	Load tripped by UFLS (MW)	DER tripped (MW)	Notes
C14	25	12	2
C18	0	0	
C19	17	35	3
C22	0	0	
C23	0	0	
C28	120	85	4
C30	0	15	5
C31	65	53	6
C34	110	62	7

Table 3.14: Table of Notes referred to in Hawaii Grid Following Study Results Table (post-tuning)

Notes	Description
1	Project's BESS has a damped oscillatory response following fault clearing.
2	Long clearing time fault results in some underfrequency load shedding. The amount of load shedding is within the allowable limits, which is 15% of the total system load.
3	UFLS happens, followed by undamped oscillations in all generators except for DER. Governor response and IBR frequency controllers may be tuned to mitigate these oscillations. The amount of load shedding is within the allowable limits, which is 15% of the total system load.
4	Loss of largest synchronous unit. DER trips on UV. Slower frequency drop results in lower initial load shed (compared to pre-tuning) preventing further frequency recovery. This causes more UFLS to trigger.
5	Loss of some DER results in small steady state under frequency. Similar to case 19 (Note 4), slow voltage collapse at some busses until frequency falls out of deadband, and IBR responds to correct it.
6	Project's BESS loses stability for a short period, resulting in a lot of UFLS.
7	Loss of large PV & BESS results in most of the load being lost due to UFLS.

3.3.3 Results Table: Grid-Forming, Pre-Tuning

The only model difference in the grid-forming simulations was a single project BESS switching from grid following to grid forming mode. Therefore, most of the grid-forming simulation results (pre-tuning) are similar to those from grid-following. Results of the priority contingencies are summarized in Table 3.15.

Table 3.15: Hawaii Table of Grid Forming Study Results (priority contingencies only, pre-tuning)

Contingency ID	Load tripped by UFLS (MW)	DER tripped (MW)	Notes
C1	0	3	
C2	0	3	1
C5	0	3	1
C6	0	10	
C9	0	4	
C10	0	4	

Contingency ID	Load tripped by UFLS (MW)	DER tripped (MW)	Notes
C13	0	3	
C14	0	6	2
C18	0	3	
C19	5	35	3
C22	110	70	4
C23	0	0	
C28	80	85	5
C30	0	15	
C31	35	42	6
C34	110	44	7

Table 3.16: Table of Notes referred to in Hawaii Grid Forming Study Results Table (pre-tuning)

Notes	Description
1	Project's BESS has a damped oscillatory response following fault clearing.
2	Long clearing time fault results in oscillatory response in IBRs and synchronous machines.
3	Undamped oscillations in all generators except for DER. Governor response and IBR frequency controllers may be tuned to mitigate these oscillations.
4	Project's BESS is unstable on reclose. UFLS results.
5	Loss of PGV. DER trips on UV.
6	Project's BESS loses stability for a short period, resulting in UFLS.
7	Loss of large PV & BESS Project results in most of the load being lost due to UFLS.

3.3.4 Results Table: Grid-Forming, Post-Tuning

The same control changes which were applied for grid-following simulations (section 3.3.2) were applied to grid-forming simulations. Tuning recommendations were not confirmed by the developers for this study and should be verified by the developers for future studies. A number of contingencies with UFLS triggering were mitigated, however, several issues remain outstanding. These will be discussed further in the next section. Summary of the results is presented in Table 3.17.

Table 3.17: Hawaii Table of Grid Forming Study Results (priority contingencies only, post-tuning)

Contingency ID	Load tripped by UFLS (MW)	DER tripped (MW)	Notes
C1	0	3	
C2	0	3	1
C3	0	3	
C4	0*	6	
C5	0	3	1
C6	0	10	

Contingency ID	Load tripped by UFLS (MW)	DER tripped (MW)	Notes
C7	0	3	
C8	0*	9	
C9	0	4	
C10	0	4	
C11	0	3	
C12	0	18	2
C13	0*	3	
C14	0	6	3
C15	0	3	
C16	0	0	
C17	0	18	2
C18	0	3	
C19	2	6	2
C20	0	0	
C21	0	0	
C22	0	0	
C23	0	0	
C24	0	3	
C25	0	3	
C26	0	3	
C27	0	16	2
C28	120	84	4
C29	0	16	2
C30	0	15	
C31	65	55	5
C32	28	30	5
C33	18	18	6
C34	110	44	7

Table 3.18: Table of Notes referred to in Hawaii Grid Forming Study Results Table (post-tuning)

Notes	Description
1	Project's BESS has a damped oscillatory response following fault clearing.
2	Undamped oscillations in all generators except for DER. Governor response and IBR frequency controllers may be tuned to mitigate these oscillations.
3	Long clearing time fault results in oscillatory response in IBRs and synchronous machines.
4	Loss of largest synchronous unit. DER trips on UV. Slower frequency drop results in lower initial load shed (compared to pre-tunning) preventing further frequency recovery. This causes more UFLS to trigger.

Notes	Description
5	Project's BESS does not respond in a stable manner (mainly reactive power control) for a short period, resulting in DER block and then UFLS.
6	Some DERs in weakly connected areas (after the line loss) see temporary voltage drop as the powerflow changes after fault recovery. DERs block and causes some UFLS to trigger.
7	Loss of large PV & BESS project results in most of the load being lost due to UFLS.

3.3.5 Plots and Discussion of Specific Issues

3.3.5.1 Priority contingencies causing system-wide load shedding

Two contingencies cause system-wide load trip (C28 and C34) even with grid forming inverters and control tuning. These contingencies simulate the loss of the largest synchronous unit and the loss of a large hybrid PV and BESS plant, respectively.

The main reason for this is the drop in system frequency due to the loss of generation and system strength. Both of the plants are main contributors to serve the system load and once one of these plants is lost (along with most of the DERs in case of PGV), the remaining generation is not sufficient to serve the system load. Hence, the system frequency drops and causes system-wide UFLS. Figure 3.14 and Figure 3.15 show the simulation results for the loss of the largest synchronous machine and a large hybrid PV and BESS project, respectively.

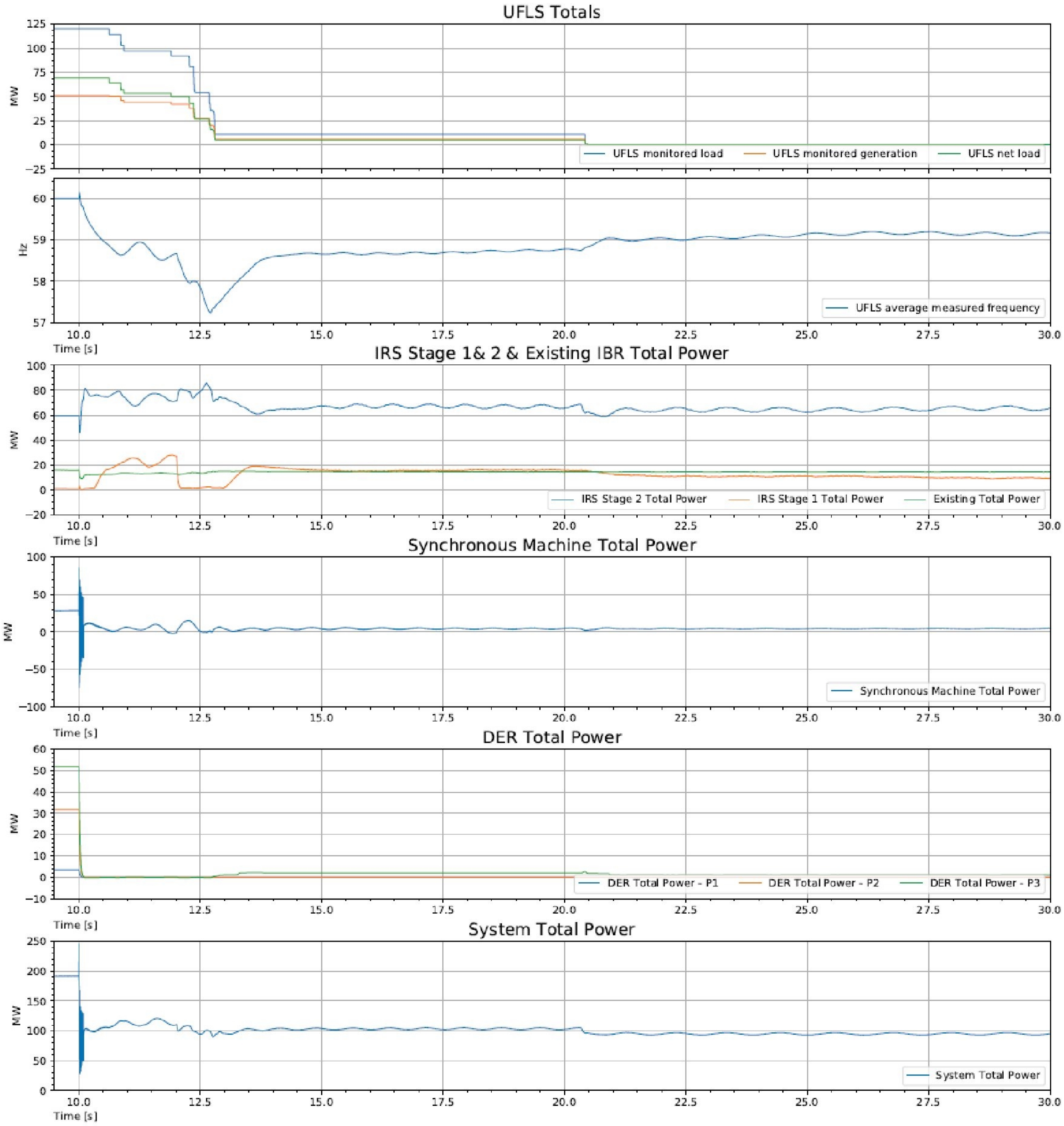

Figure 3.14: Loss of largest synchronous unit leading to load shedding (Hawaii grid-forming case).

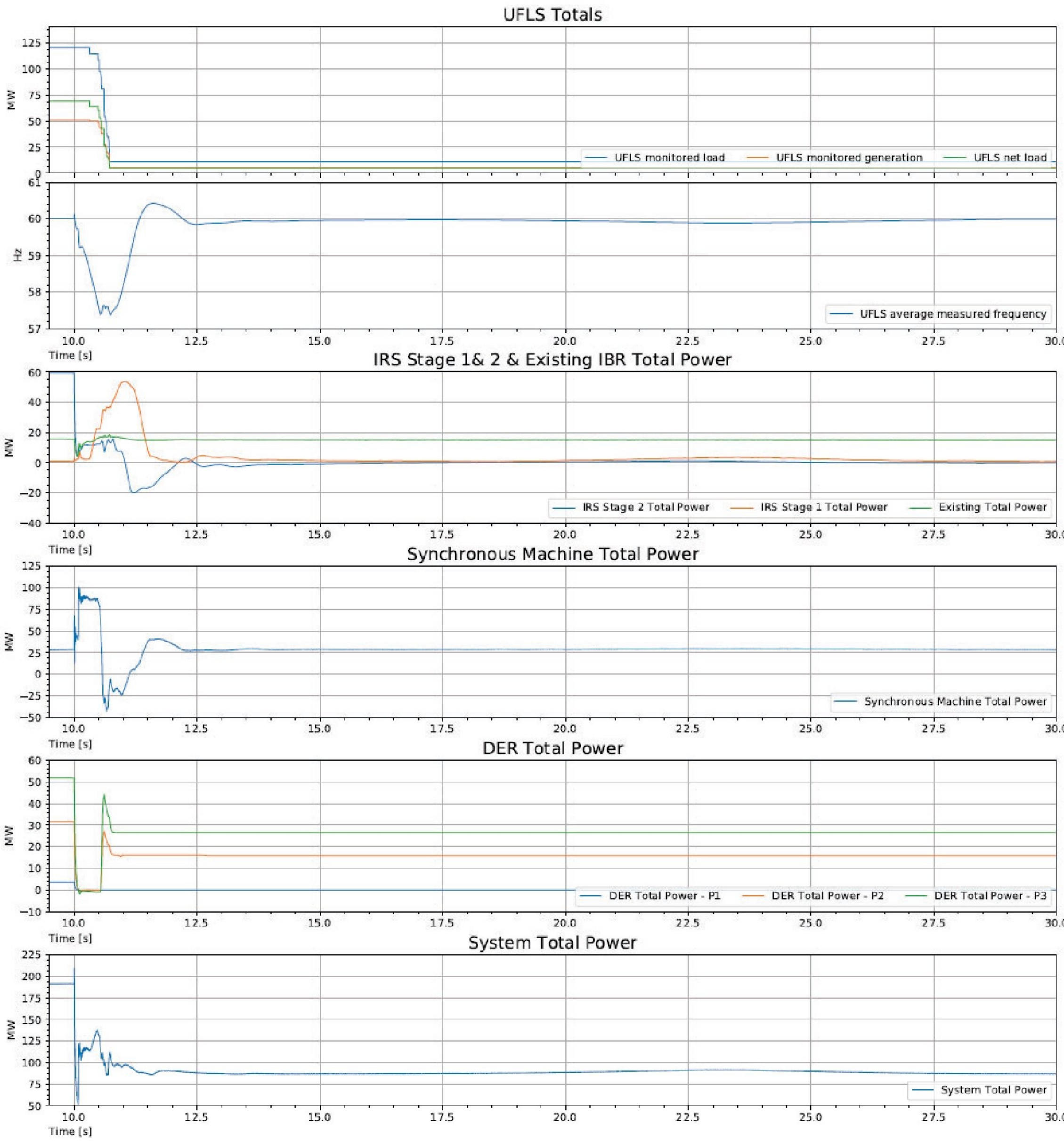

Figure 3.15: Loss of large PV and BESS project leading to load shedding (Hawaii grid-forming case).

3.3.5.2 Slow or oscillatory voltage recovery

Several cases in the pre-tuning results show that the system voltage recovery is slow and, in some cases, oscillatory. One main reason for the voltage remaining low is a Stage 2 project's BESS plant (grid forming) loses stability for a short period during the recovery and does not provide both active and reactive power support. In some contingencies, this caused system-wide load shedding.

This condition was improved by modifying the LVRT settings in the inverter model. However, there are several cases with slow voltage recovery where a specific plant does not support the recovery. Figure 3.16 and Figure 3.17 show the pre and post tuning results of the plant for C22. Figure 3.18 and Figure 3.19 show the project's BESS and PV results for a case for which control tuning could not avoid a period of instability from the plant during fault recovery (C31). In this case, the grid-forming BESS does not behave in the expected manner. There is no inertial power support and the BESS absorbs reactive power during the undervoltage, suggesting the BESS may be prioritizing current-limiting control over grid-forming control. The PV inverters are also unable to inject active and reactive current in a stable manner during this condition. Further effort is needed to tune the response of the plant to respond in a stable manner during this contingency.

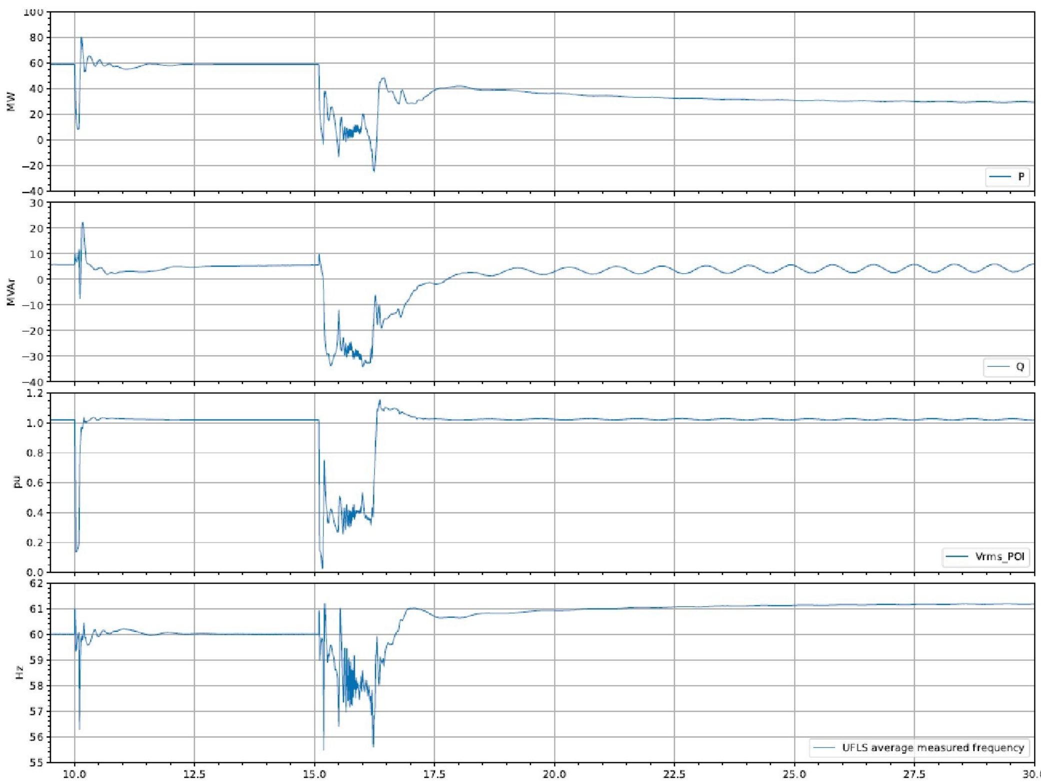

Figure 3.16: Results for C22 in the pre-tuning, grid-forming scenario. Note that the plant is absorbing about 0.5 pu reactive power during the undervoltage, following the reclose attempt.

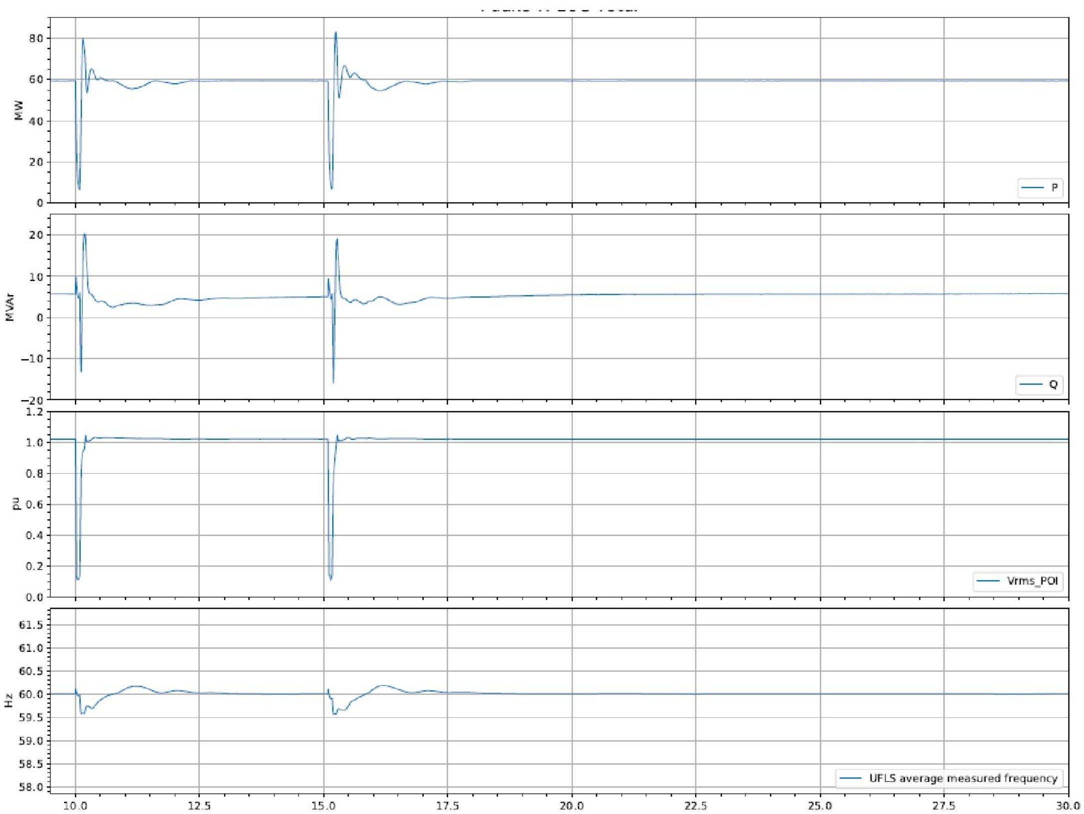

Figure 3.17: Results for C22 in the post-tuning, grid-forming scenario. Note that the plant returns to normal, stable operation very quickly after the initial fault and the reclosing attempt.

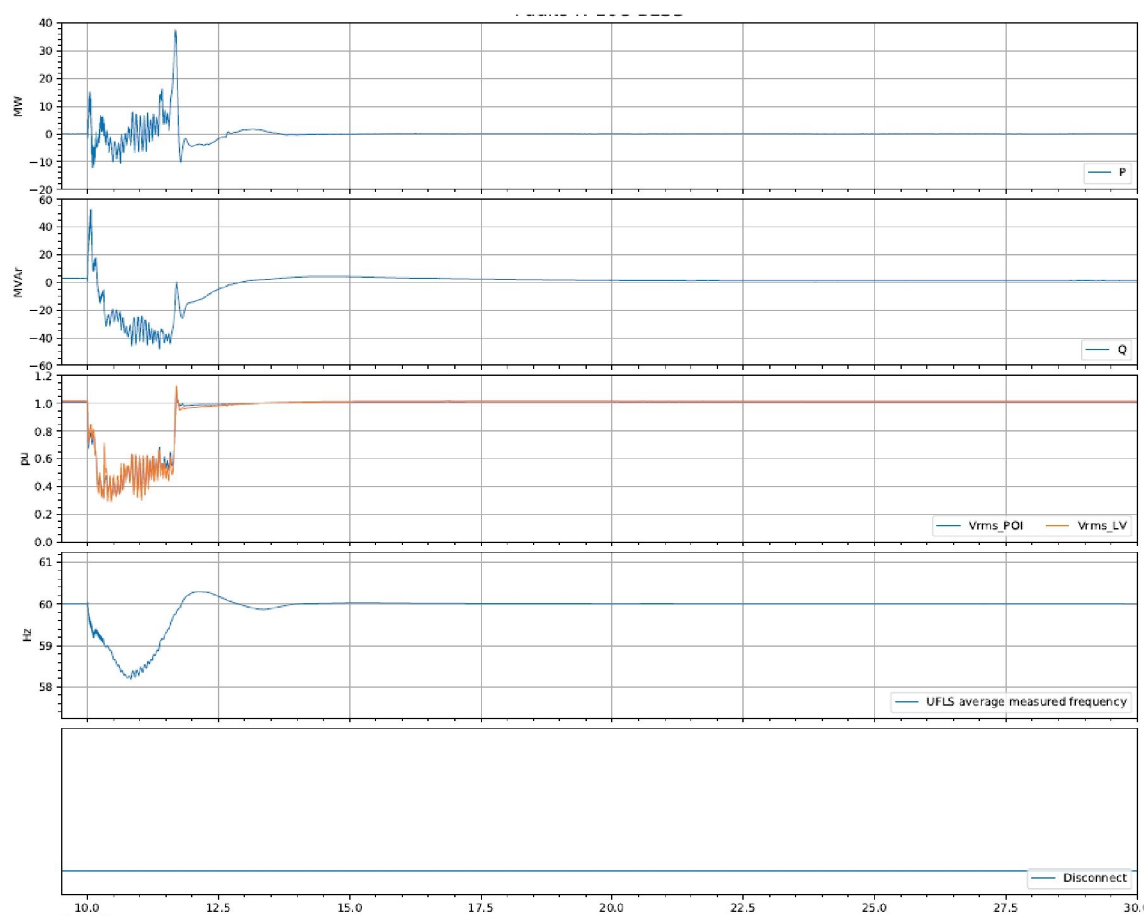

Figure 3.18: Project's BESS results for C31 in the post-tuning, grid-forming scenario. Note that the BESS does not contribute to frequency support and that the BESS absorbs reactive power during the undervoltage, exacerbating the condition.

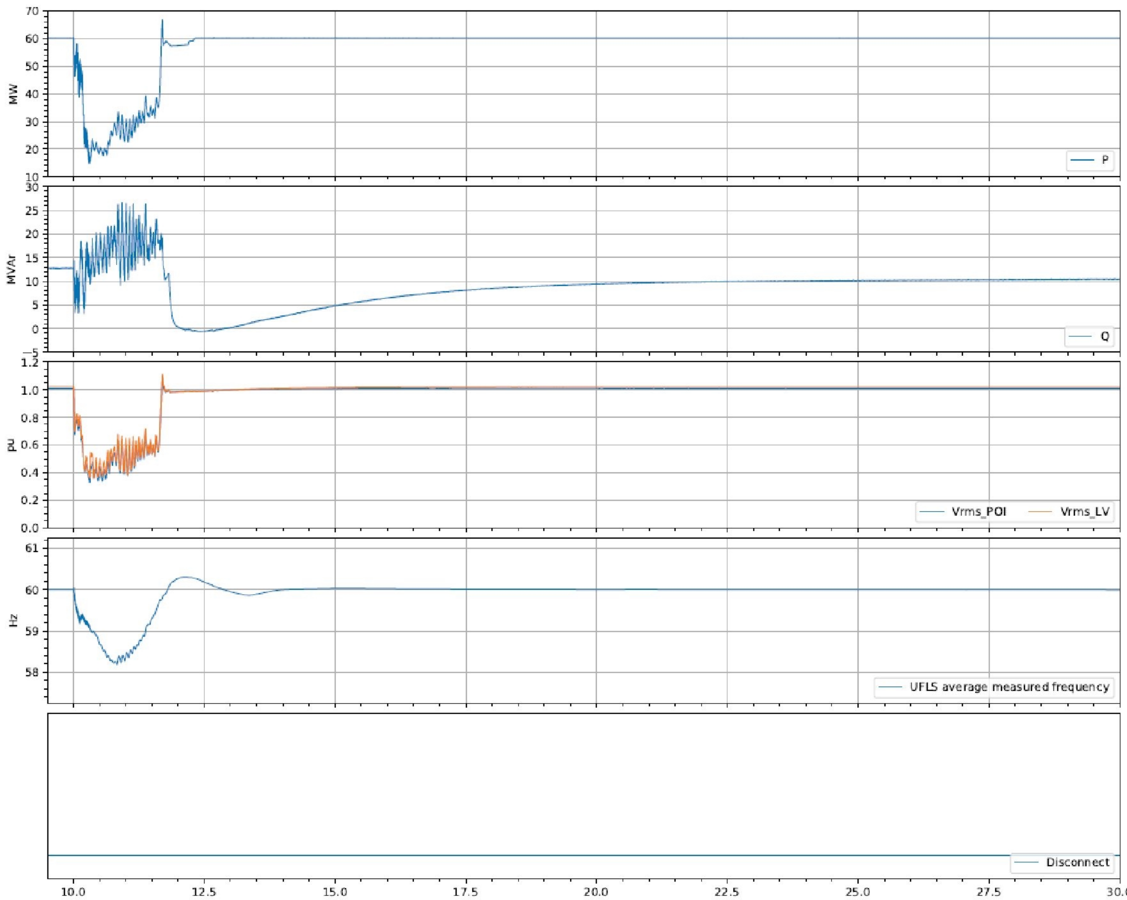

Figure 3.19: Project's PV results for C31 in the post-tuning, grid-forming scenario. Note that the PV does not contribute to frequency support and that PV reactive power output is very noisy.

3.3.5.3 System-wide oscillations

As in the Maui system, sustained oscillations were observed with the 3PH fault with delayed clearing (C19) in both grid following and grid forming cases. The frequency of these oscillations ranged from 0.3 Hz up to 1 Hz where the synchronous machines seem to oscillate against the IBRs. The amount of load shedding following the contingency was reduced with grid forming simulations. Figure 3.20 shows the simulation results for C19 for Post-tuning (grid forming) case. Further investigation is required into the reason for these oscillations and into potential mitigations.

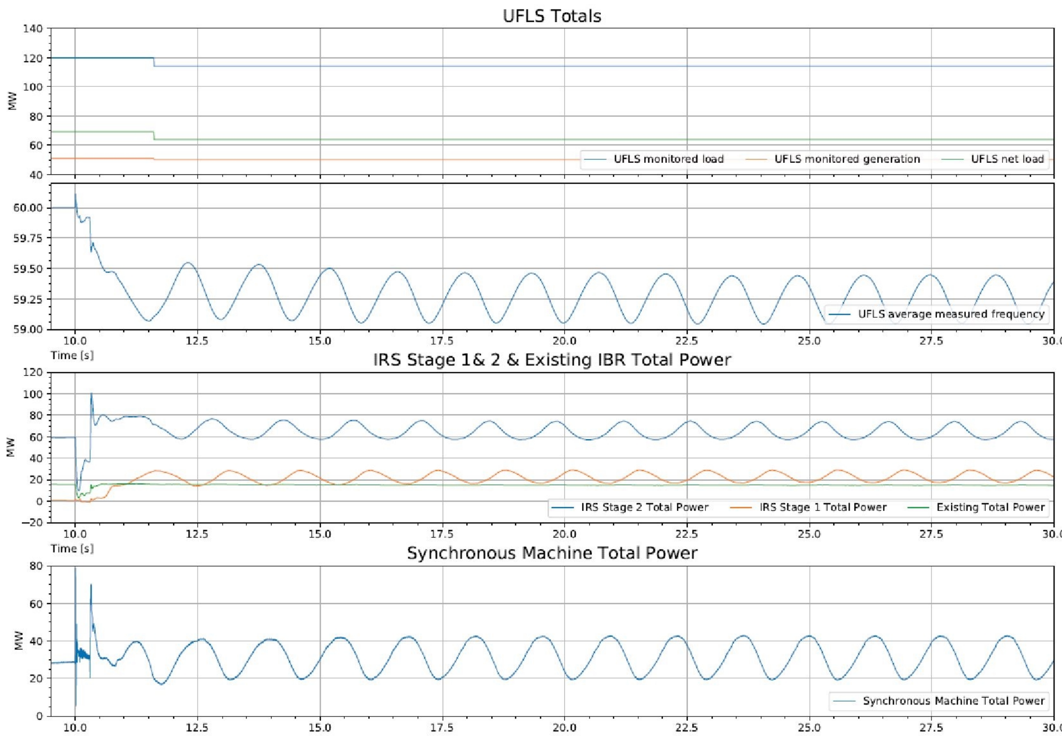

Figure 3.20: 3PH fault with delayed clearing (C19) leading to system-wide oscillations (Hawaii grid-forming case).

Appendix A – Project Specific Recommendations

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